Southern Power
600 North 18th Street
Birmingham, Alabama 35203-2206

205-257-6720

SOUTHERN POWER
A SOUTHERN COMPANY

June 27, 2013

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Application for a Prevention of Significant Deterioration Air Quality Permit for Greenhouse Gas Emissions;
Biological Assessment;
Cultural Resources Assessment;
Trinidad Generating Facility
Trinidad, Henderson County, Texas

Mr. Robinson:

Southern Power Company (SPC) is hereby submitting this application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions for the construction of a new natural gas fired combined-cycle electric generating plant, Trinidad Generating Facility, to be located in Trinidad, Henderson County, Texas. The state/PSD application for non-greenhouse gas emissions are being submitted concurrently to the Texas Commission on Environmental Quality (TCEQ).

General information for the application is provided on the TCEQ Form PI-1 - General Application for Air Preconstruction Permit and Amendments. The U.S. Environmental Protection Agency's (EPA) document entitled *"PSD and Title V Permitting Guidance For Greenhouse Gases", dated November 2010 and March 2011,* was utilized as a guide for preparation of the attached application.

The supporting Biological Assessment and Cultural Resources Assessment for the project are also attached. SPC is committed to working closely with EPA Region 6 to get the application review completed as expeditiously as possible. We will be contacting your staff soon after submittal of this application to arrange a meeting to review the application and answer any questions that your team may have developed after initially reading our application.

Should you have any questions regarding this application or supporting Biological Assessment or Cultural Resources Assessment, please contact Kelli McCullough at kamccull@southernco.com or by telephone at (205) 257-6720.

Sincerely,

Susan Comensky

Susan Comensky
Vice President, External & Regulatory Affairs

Enclosure

cc: Mr. Mike Wilson, P.E., Director, Air Permits Division, TCEQ

Mr. Edward Rapier, P.E., Zephyr Environmental Corporation

PREVENTION OF SIGNIFICANT DETERIORATION GREENHOUSE GAS PERMIT APPLICATION FOR SOUTHERN POWER COMPANY COMBINED CYCLE POWER PLANT, TRINIDAD GENERATING FACILITY HENDERSON COUNTY, TEXAS

SUBMITTED TO:

ENVIRONMENTAL PROTECTION AGENCY
REGION 6
MULTIMEDIA PLANNING AND PERMITTING DIVISION
FOUNTAIN PLACE 12TH FLOOR, SUITE 1200
1445 ROSS AVENUE
DALLAS, TEXAS 75202-2733

SUBMITTED BY:

SOUTHERN POWER COMPANY
600 NORTH 18TH STREET
BIRMINGHAM, ALABAMA 35203

PREPARED BY:

ZEPHYR ENVIRONMENTAL CORPORATION
2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746

JUNE 27, 2013

CONTENTS

TABLES

APPENDICES

1.0 INTRODUCTION

In May 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how Prevention of Significant Deterioration (PSD) preconstruction and Title V permit programs would be applied to greenhouse gas (GHG) emissions from stationary sources, including power plants. Currently, in accordance with the Tailoring Rule, new sources that have the potential to emit 100,000 tons per year or more of GHGs, new sources that are major for PSD for non-GHG pollutants and that have the potential to emit 75,000 tons per year or more of GHGs, and existing major sources that perform a project that increases GHG emissions over 75,000 tons per year or more must go through the PSD permitting process and install the best available control technology (BACT) for GHGs.

On December 23, 2010, EPA issued a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas until Texas submits the required SIP revision for GHG permitting and it is approved by EPA. PSD permitting for the non-GHG PSD pollutants continues to be regulated by the Texas Commission on Environmental Quality (TCEQ).

On May 21, 2013, the Texas Legislature passed House Bill 788, and the Governor signed it into law on June 14 2013. This new law directs the TCEQ to adopt rules to authorize GHG emissions through state issued permits. HB 788 contemplates a transitioning of applications from EPA to TCEQ, which will certainly be the subject of coordination between EPA and TCEQ in the coming weeks and months, and it is foreseeable that this application will be transitioned back to TCEQ as a part of that process.

Note that the State and PSD air permit application for non-GHG pollutants was submitted to the TCEQ on June 27, 2013.

Southern Power Company (SPC) proposes to construct a natural gas-fired combined-cycle power plant in Henderson County, Texas, to be called the Trinidad Generating Facility (TGF). The plant will consist of one natural gas-fired combustion turbine generator, exhausting to a heat recovery steam generator (HRSG) with supplemental firing capability to produce steam to drive a steam turbine, and associated support facilities. The combustion turbine planned for this site is the Mitsubishi Heavy Industries (MHI) J model, with a nominal maximum combined-cycle gross electric power output of approximately 530 MW.

The proposed project triggers PSD review for GHG regulated pollutants because estimated potential emissions will total more than 100,000 tons/yr of GHGs. Included in this application are a project scope description, GHG potential emissions calculations, and a GHG BACT analysis.

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

Important Note: The agency requires that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Southern Power Company		
Texas Secretary of State Charter/Registration Number (if applicable): TBD		
B. Company Official Contact Name: Susan Comensky		
Title: VP of External and Regulatory Affairs		
Mailing Address: PO Box 2641, Bin 15N-8198		
City: Birmingham	State: AL	ZIP Code: 35203-2206
Telephone No.: 205-257-2098	Fax No.:	E-mail Address: scomensk@southernco.com
C. Technical Contact Name: Kelli McCullough		
Title:		
Company Name: Southern Power Company		
Mailing Address: 600 North 18th Street, Bin 14N-8195		
City: Birmingham	State: AL	ZIP Code: 35203
Telephone No.: 205-257-6720	Fax No.:	E-mail Address: kamccull@southernco.com
D. Site Name: Trinidad Generating Facility		
E. Area Name/Type of Facility: Electric Generating Facility	☒ Permanent ☐ Portable	
F. Principal Company Product or Business: Generation of Electricity		
Principal Standard Industrial Classification Code (SIC): 4911		
Principal North American Industry Classification System (NAICS): 221112		
G. Projected Start of Construction Date: March 2015		
Projected Start of Operation Date: June 2017		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: From Highway 31, head north on Forehand Road. Site is located east of Highway 274 and west of Forehand Road, approximately ¾ mile north of Highway 31.		
City/Town: Trinidad	County: Henderson	ZIP Code: 75163
Latitude (nearest second): 32^0 09’ 38.89”N	Longitude (nearest second): 96^0 05’ 34.48”W	

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility):	
J.	Core Data Form.	
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).		☒ YES ☐ NO
K.	Customer Reference Number (CN):	
L.	Regulated Entity Number (RN):	
II.	**General Information**	
A.	Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C.	Number of New Jobs: ~ 25	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Robert Nichols		District No.: 3
State Representative: Jim Pitts		District No.: 10
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested.	
☒ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation		
B.	Permit Number (if existing):	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*	
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit		
☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source		
☐ Other:		
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III.	Type of Permit Action Requested *(continued)*	
E.	Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0	☐ YES ☒ NO
1.	Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):	
Street Address:		
City:	County:	ZIP Code:
2.	Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):	
Street Address:		
City:	County:	ZIP Code:
3.	Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.	☐ YES ☐ NO
4.	Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?	☐ YES ☐ NO
F.	Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.	
List:		
G.	Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.	☒ YES ☐ NO
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).	☒ YES ☐ NO ☐ To be determined
Associated Permit No (s.): Associated permit has not yet been issued.		
1.	Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved. ☐ FOP Significant Revision ☐ FOP Minor ☐ Application for an FOP Revision ☐ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☒ To be Determined ☐ None	

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

III. Type of Permit Action Requested *(continued)*		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*		
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***		
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued	☐ SOP application/revision application submitted or under APD review	
IV. Public Notice Applicability		
A. Is this a new permit application or a change of location application?		☒ YES ☐ NO
Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.		☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?		☐ YES ☒ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?		☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.		
1. Is there any change in character of emissions in this application?		☐ YES ☐ NO
2. Is there a new air contaminant in this application?		☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?		☐ YES ☐ NO
F. List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***		
Volatile Organic Compounds (VOC): 531.5 tons		
Sulfur Dioxide (SO2): 9.8 tons		
Carbon Monoxide (CO): 903.1 tons		
Nitrogen Oxides (NOx): 140.6 tons		
Particulate Matter (PM): 63.5 tons		
PM 10 microns or less (PM10): 61.3 tons		
PM 2.5 microns or less (PM2.5): 58.1 tons		
Lead (Pb): N/A		
Hazardous Air Pollutants (HAPs): <10 single HAP, < 25 total HAP		
Other speciated air contaminants not listed above: 4.5 tons H2SO4, 6.0 tons (NH4)2SO4, 131.7 tons NH3		

V. Public Notice Information ***(complete if applicable)***		
A. Public Notice Contact Name: Kelli McCullough		
Title: Environmental Engineer		
Mailing Address: 600 N 18th St, Bin 15N-8195, PO Box 2641		
City: Birmingham	State: AL	ZIP Code: 35291
B. Name of the Public Place: Clint W. Murchison Memorial Library		
Physical Address *(No P.O. Boxes)*: 121 S Prairieville St		
City: Athens	County: Henderson	ZIP Code: 75751
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: Richard Sanders		
Mailing Address: 125 N. Prairieville Street		
City: Athens	State: TX	ZIP Code: 75751
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive: Terri Newhouse, City Administrator		
Mailing Address: 212 Park Street		
City: Trinidad	State: TX	ZIP Code: 75163
Name of the Indian Governing Body: NA		
Mailing Address:		
City:	State:	ZIP Code:

V.	**Public Notice Information *(complete if applicable) (continued)***	
C.	Concrete Batch Plants, PSD, and Nonattainment Permits	
3.	Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s): N/A		
D.	Bilingual Notice	
Is a bilingual program required by the Texas Education Code in the School District?		☐ YES ☒ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☐ YES ☒ NO
If Yes, list which languages are required by the bilingual program?		
VI.	**Small Business Classification *(Required)***	
A.	Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B.	Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C.	Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D.	Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII.	**Technical Information**	
A.	The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
1.	☒ Current Area Map	
2.	☒ Plot Plan	
3.	☒ Existing Authorizations	
4.	☒ Process Flow Diagram	
5.	☒ Process Description	
6.	☒ Maximum Emissions Data and Calculations	
7.	☒ Air Permit Application Tables	
a.	☒ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b.	☒ Table 2 (Form 10155) entitled, Material Balance	
c.	☒ Other equipment, process or control device tables	
B.	Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO

VII.	**Technical Information**			
C.	Maximum Operating Schedule:			
Hour(s): 24 hr/day	Day(s): 7 day/week	Week(s): 52 week/year	Year(s): 8,760 hr/year	
Seasonal Operation? If Yes, please describe in the space provide below.				☐ YES ☒ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.				
MSS activities are listed on Tables A-14 and A-15 of the attached application.				
This is a new site and there have been no previous emission inventories.				
E.	Does this application involve any air contaminants for which a disaster review is required?			☒ YES ☐ NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?			☐ YES ☒ NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			☒ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☐ YES ☒ NO

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		
XI.	**Permit Fee Information**	
Check, Money Order, Transaction Number ,ePay Voucher Number:		Fee Amount: $
Paid online?		☐ YES ☐ NO
Company name on check:		
Is a copy of the check or money order attached to the original submittal of this application?		☐ YES ☐ NO ☒ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?		☐ YES ☐ NO ☒ N/A

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

XII. Delinquent Fees and Penalties
This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.
XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Susan Comensky
Signature: Susan Comensky *Original Signature Required*
Date: 6/27/13

2.0 PROJECT SCOPE

2.1 INTRODUCTION

With this application, SPC is seeking a GHG permit authorization for a new combined-cycle electric generating facility, TGF, in Henderson County, Texas to be fueled by pipeline-quality natural gas. SPC has determined that a combined-cycle unit that will produce a nominal maximum gross electric power output of approximately 530 MW is needed to reliably and economically meet the needs of SPC's customers that will be served by this project. In addition, to most effectively meet these needs, the combined-cycle unit must be capable of operating in a range of modes, which includes the use of duct burners and evaporative cooling. The power generating equipment and ancillary equipment that will be potential sources of GHG emissions at the site are summarized below:

- One natural gas-fired combined-cycle combustion turbine equipped with lean pre-mix low-NO_x combustors;
- One natural gas-fired duct burner system;
- One natural gas-fired auxiliary boiler;
- One diesel fuel-fired firewater pump engine;
- Natural gas piping and handling and metering equipment; and
- Electrical equipment insulated with sulfur hexafluoride (SF_6). Although the equipment containing SF_6 is designed to be leak proof, and therefore is not expected to be a source of emissions, SPC has calculated potential SF_6 emissions to be conservative.

A process flow diagram is included at the end of this section.

Pipeline-quality natural gas is chosen as the only fuel for the combustion turbine and duct burner system due to local availability of this fuel and the infrastructure to support delivery of this fuel to the facility in adequate volume and pressure.

The combined-cycle unit will fulfill the obligations of SPC by reliably and economically meeting the needs of its customers while meeting applicable environmental requirements.

2.2 COMBUSTION TURBINE GENERATOR (CTG) AND HRSG

The CTG burns pipeline-quality natural gas to rotate an electrical generator. The main components of the CTG turbine consist of a compressor, combustor, turbine, and generator. The compressor pressurizes the inlet combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the expansion turbine where the gases expand across the turbine blade, which generates torque that drives a shaft to power an electric generator. The temperature of the inlet air to the CTG proposed for TGF will at times be lowered using evaporative cooling to increase the mass air flow through the turbine and achieve maximum turbine power output on days with warm to hot ambient conditions.

The exhaust gases from the combustion turbine will be directed through an HRSG. The HRSG will be equipped with duct burners for supplemental steam production. Duct burning involves burning natural gas in the heat recovery boiler duct, which increases the temperature of the exhaust coming from the combustion turbines into the HRSG and thereby creates additional steam for the steam turbine. The duct burner firing provides additional power generation capacity during periods of high demand. The duct burners will be fired with pipeline-quality natural gas. The duct burners have a nominal maximum rated heat input capacity of approximately 402 MMBtu/hr. The exhaust gases from the unit, including emissions from the combustion turbine and the duct burners, will exit through a stack to the atmosphere. The emission point number (EPN) for the combustion turbine/HRSG unit is given as U1-STK.

The normal duct burner operation will vary from 0 to 100 percent of the maximum capacity. Duct burners will be located in the duct to the HRSG, prior to the selective catalytic reduction system.

Steam produced by the HRSG will be routed to the steam turbine. The combustion turbine and steam turbine will be coupled to an electric generator to produce electricity for sale to the Electric Reliability Council of Texas power grid. The MHI J combined-cycle unit will produce a nominal maximum gross electric power output of approximately 530 MW. The unit load will vary to respond to changes in system power requirements and/or stability.

Startup and shutdown of the proposed combined-cycle unit is part of the regularly scheduled operations at the facility. Startup and shutdown periods for the combustion turbine are defined by monitored operating conditions. For the combustion turbine, a startup is defined as the period from when an initial flame detection signal is recorded in the plant's Data Acquisition and Handling System (DAHS) and ends with the achievement of the minimum output level (approximately 50 percent) at which the unit has been demonstrated by a CEMS or during a compliance test to have met the normal steady state operating emission limits. The shutdown period begins when the combustion turbine output drops below the start-up end point as indicated in the previous sentence, and ends when the flame detection signal is no longer recorded in the plant's DAHS.

2.3 AUXILIARY BOILER

One auxiliary boiler (EPN AUXBLR1) will be required to facilitate startup of the combined-cycle unit. The auxiliary boiler will have a maximum heat input of 110 MMBtu/hr and will burn pipeline-quality natural gas. The auxiliary boiler will operate up to 1,500 hours per year.

2.4 DIESEL FIRED EMERGENCY EQUIPMENT

The site will be equipped with one 160-hp firewater pump (EPN FWP1-STK) The engine running this equipment will fire ultra low-sulfur diesel fuel. Operation of the firewater pump will be limited to 100 hours per year when operated for the purposes of maintenance checks and readiness testing.

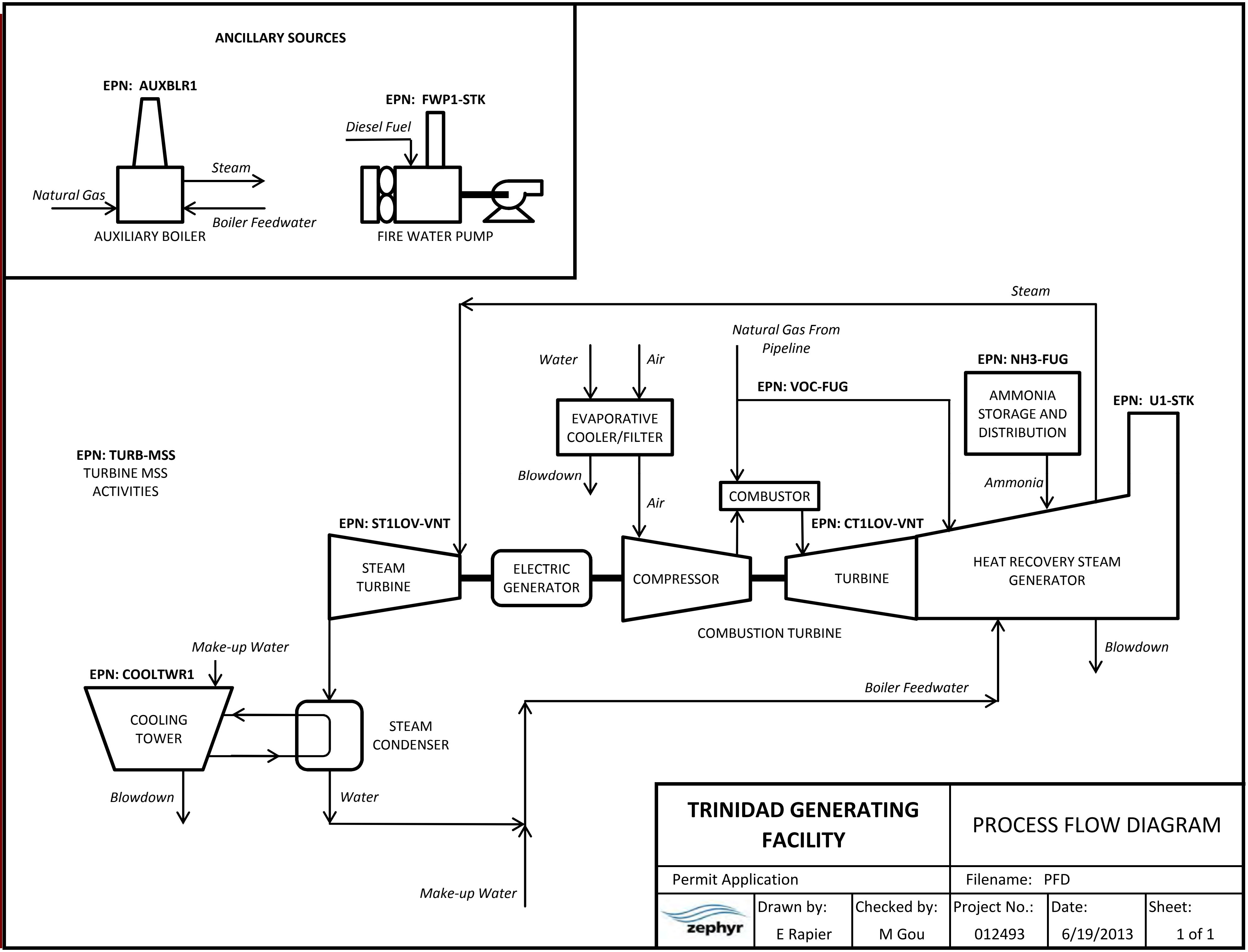
2.5 NATURAL GAS PIPING FUGITIVES

Natural gas will be delivered to the site via pipeline and then metered and piped to the combustion turbine. Fugitive emissions from the gas piping components associated with the new CTG/HRSG unit will include emissions of methane (CH_4) and carbon dioxide (CO_2). Fugitive emissions of natural gas are designated as EPN VOC-FUG.

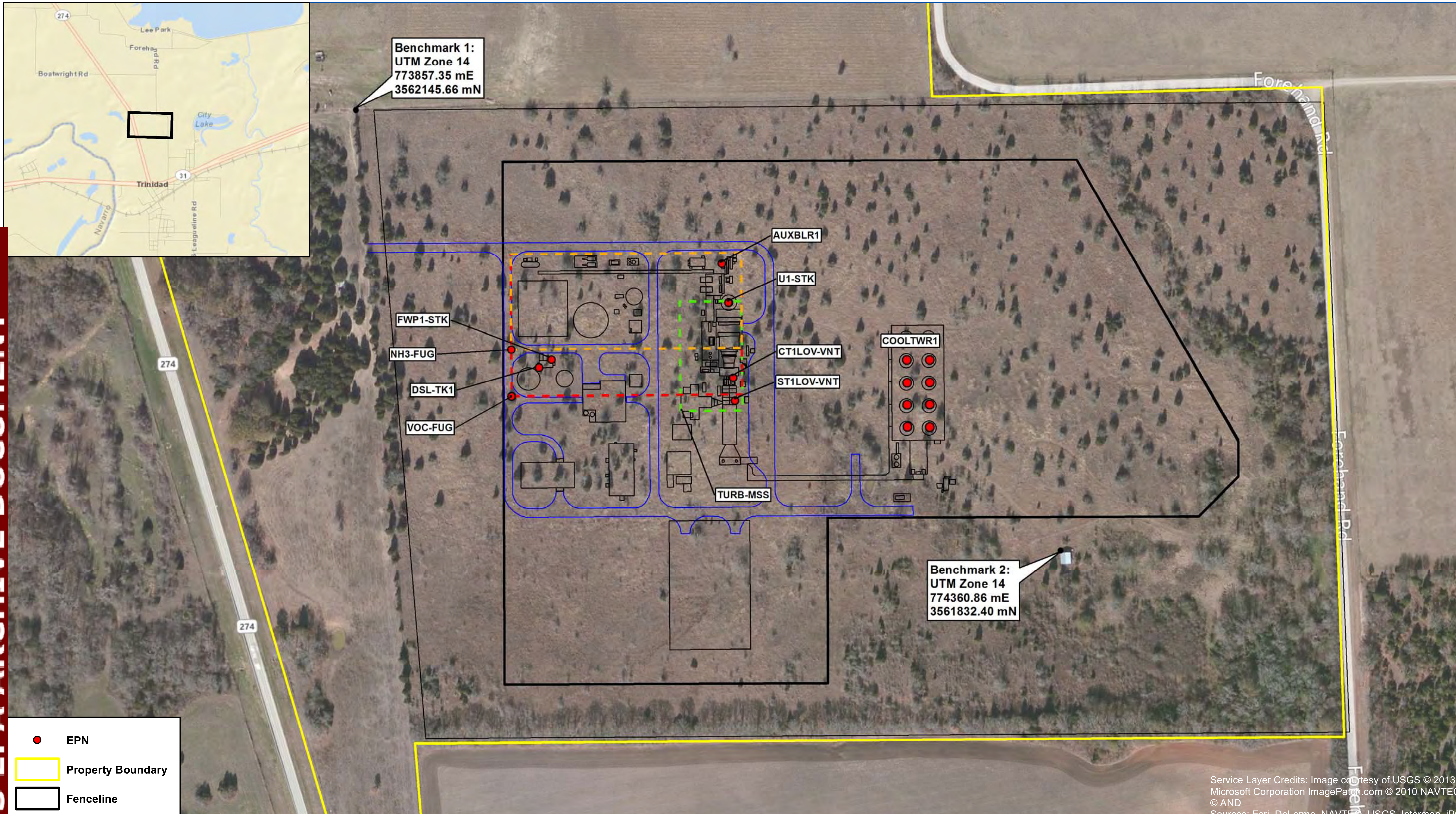
2.6 ELECTRICAL EQUIPMENT INSULATED WITH SULFUR HEXAFLUORIDE (SF_6)

The generator circuit breakers associated with the proposed unit will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 365 lb of SF_6. Although fugitive emissions of SF_6 are not expected because the equipment is designed to be leak free, to be conservative SF_6 emissions are included in this application.

The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of “quenching and cooling” SF_6 gas.

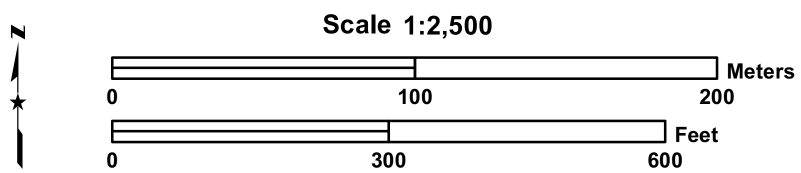


TRINIDAD GENERATING FACILITY		PROCESS FLOW DIAGRAM			
Permit Application		Filename: PFD			
zephyr	Drawn by: E Rapier	Checked by: M Gou	Project No.: 012493	Date: 6/19/2013	Sheet: 1 of 1



Map Sources:
ESRI Basemaps-
Bing Hybrid & Streets Basemaps;
Southern Power Company

Scale 1:2,500



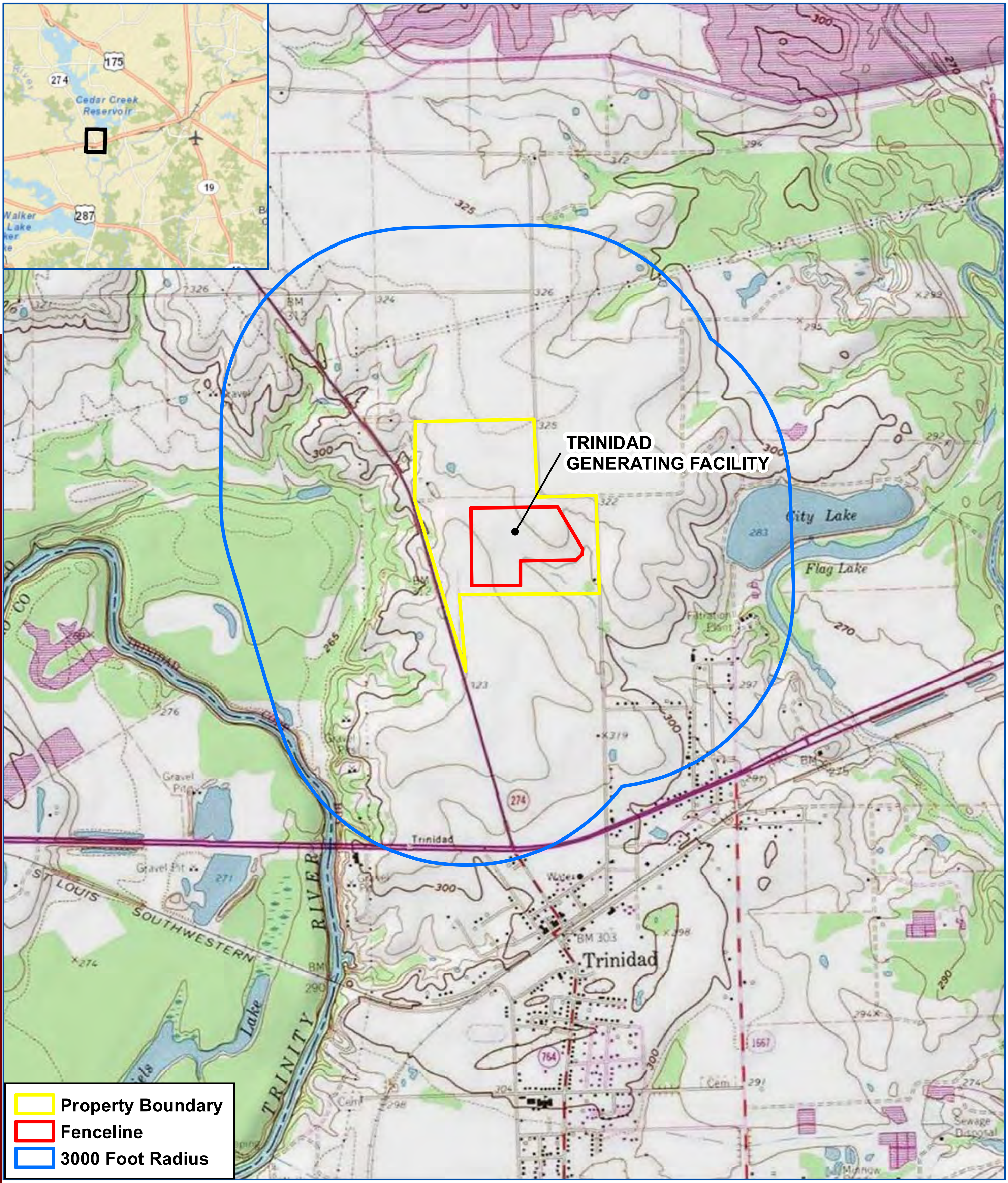
zephyr

PLOT PLAN - TRINIDAD GENERATING FACILITY

Southern Power Company - Henderson County, Texas

File Location: H:\Southern Company\012493 Henderson County Combined Cycle Gas Turbines\GIS\PDFs

Drafted By: J. Knowles	Reviewed By: E. Rapier	Project No.: 012493.006	Date: 06.11.2013



Data Sources: ESRI- USGS Topographic & Streets Basemaps, Datum: GCS NAD 83

Scale 1:24,000

0 0.5 1 Kilometers

0 0.5 1 Miles

zephyr

AREA MAP - Topographic Map
TRINIDAD GENERATING FACILITY

SOUTHERN POWER COMPANY
Henderson County, TX

Drafted By:	Reviewed By:	Project No.:	Date:
J. Knowles	E. Rapier	012493.006	06.11.2013

3.0 GHG POTENTIAL EMISSION CALCULATIONS

PSD applicability to GHG emissions from a source is based on CO_2 equivalent (CO_2e) emissions as well as its GHG mass emissions. CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP), obtained from Table A-1 of the Mandatory Greenhouse Gas Reporting Program (GHGRP) (40 CFR Part 98, Subpart A). Consequently, when determining the applicability of PSD to GHGs, there is a two-part applicability process that evaluates both:

- The sum of the CO_2e emissions in TPY of the six GHGs, in order to determine whether the source's emissions are a regulated NSR pollutant; and, if so

- The sum of the mass emissions in TPY of the six GHGs, in order to determine whether the source's emissions trigger the PSD major source or modification thresholds.

GHG species directly emitted by the combustion of natural gas from this project are CO_2, nitrous oxide (N_2O), and CH_4. Although emissions are not expected, potential emissions of sulfur hexafluoride (SF_6) are also accounted for in the calculations. Two other GHG species – hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) – have no potential to be emitted.

The GHGs under consideration are generated from combustion of carbon-containing fuel (e.g., CO_2), the incomplete combustion of fuel (CH_4), or the partial reaction of nitrogen compounds within the fuel or air during the combustion process (N_2O). CO_2 is the dominant GHG emission, with methane and nitrous oxide being emitted in trace quantities. The production rate of these species depends on the fuel composition, the details of the combustion conditions, and net thermal efficiency of the generating unit. Plant-wide GHG emissions are summarized on Table 3-1.

3.1 GHG EMISSIONS FROM COMBINED-CYCLE COMBUSTION TURBINE

GHG emissions for the combustion turbine and HRSG are calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart D – Electric Generation.[1] Annual CO_2 emissions are calculated using the methodology in equation G-4 of the Acid Rain Rules.[2]

$$W_{CO_2} = \left(\frac{F_C \times H \times U_f \times MW_{CO_2}}{2000} \right) \qquad (Eq.\ G\text{-}4)$$

Where:

[1] 40 CFR 98, Subpart D – *Electricity Generation*.
[2] 40 CFR. 75, Appendix G – *Determination of CO_2 Emissions.*

W_{CO2} = CO_2 emitted from combustion, tons/yr

MW_{CO2} = Molecular weight of carbon dioxide, 44.0 lb/lb-mole

F_c = Carbon based F-factor, 1,040 scf/MMBtu for natural gas

H = Annual heat input in MMBtu

U_f = 1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F.

Emissions of CH_4 and N_2O are calculated using the emission factors (kg/MMBtu) for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[3] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.

Calculations of potential GHG emissions from the combined-cycle turbine are presented on Tables 3-2 and 3-3.

3.2 GHG EMISSIONS FROM AUXILIARY BOILER

CO_2 emissions from the natural gas-fired auxiliary boiler are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[4] CH_4 and N_2O emissions from the auxiliary boiler are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[5] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[6]

Calculations of potential GHG emissions from the auxiliary boiler are presented on Table 3-4.

3.3 GHG EMISSIONS FROM NATURAL GAS PIPING FUGITIVES AND NATURAL GAS MAINTENANCE AND STARTUP/SHUTDOWN RELATED RELEASES

GHG emission calculations for natural gas/fuel gas piping component fugitive emissions are based on emission factors from Table W-1A of the "2012 Technical Corrections, Clarifying and Other Amendments to the Greenhouse Gas Reporting Rule, and Confidentiality Determinations for Certain Data Elements of the Fluorinated Gas Source Category" which was signed on August 3, 2012[7]. The concentrations of CH_4 and CO_2 in the natural gas are based on a typical natural gas analysis. Since the CH_4 and CO_2 content of natural gas is variable, the concentrations of CH_4 and CO_2 from the typical natural gas analysis are used as an estimate.

[3] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 CFR. 98, Subpt. C, Tbl. C-2
[4] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 CFR. 98, Subpt. C, Tbl. C-1
[5] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 CFR. 98, Subpt. C, Tbl. C-2
[6] *Global Warming Potentials*, 40 CFR. Pt. 98, Subpt. A, Tbl. A-1
[7] http://www.epa.gov/ghgreporting/reporters/notices/corrections.html

The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[8] These factors are applied to a conservative fugitive component count to calculate the potential GHG emissions.

GHG emission calculations for releases of natural gas related to piping maintenance and turbine startup/shutdowns are calculated using the same CH_4 and CO_2 concentrations as natural gas/fuel gas piping fugitives.

Calculations of potential GHG emissions from natural gas piping fugitives are presented on Table 3-5. Calculations of GHG emissions from releases of natural gas related to piping maintenance and turbine maintenance and startup/shutdown activities are presented on Table 3-6.

3.4 GHG EMISSIONS FROM DIESEL-FIRED EMERGENCY ENGINE

CO_2 emission calculations from the diesel-fired firewater pump engine are calculated using the emission factors (kg/MMBtu) for Distillate Fuel Oil No. 2 from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[9] CH_4 and N_2O emission calculations from the diesel-fired engine are calculated using the emission factors (kg/MMBtu) for Petroleum from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[10] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[11]

Calculations of potential GHG emissions from the emergency engine are presented on Table 3-7.

3.5 GHG EMISSIONS FROM ELECTRICAL EQUIPMENT INSULATED WITH SF_6

SF_6 emissions from the new generator circuit breaker and yard breaker associated with the proposed unit are calculated using a conservative SF_6 annual leak rate of 0.5% by weight. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[12]

Calculations of potential GHG emissions from electrical equipment insulated with SF_6 are presented on Table 3-8.

[8] *Global Warming Potentials*, 40 CFR. Pt. 98, Subpt. A, Tbl. A-1
[9] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 CFR. 98, Subpt. C, Tbl. C-1
[10] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 CFR. 98, Subpt. C, Tbl. C-2
[11] *Global Warming Potentials*, 40 CFR. Pt. 98, Subpt. A, Tbl. A-1
[12] *Global Warming Potentials*, 40 CFR. Pt. 98, Subpt. A, Tbl. A-1

Table 3-1
Plantwide GHG Emission Summary
Southern Power Company - Trinidad Generating Facility

Name	EPN	GHG Mass Emissions ton/yr	CO_2e ton/yr
Unit 1 (MHI J)	U1-STK	1,673,224	1,674,804
Auxiliary Boiler	AUXBLR1	9,643	9,653
VOC Fugitives	VOC-FUG	10	213
ILE Turbine Maintenance Fugitives	TURB-MSS	0.14	3
Fire Water Pump	FWP1-STK	13	13
SF_6 Insulated Equipment	SF6-FUG	0.0009	22
	Sitewide Emissions:	**1,682,891**	**1,684,707**

Table 3-2

GHG Emission Calculations - MHI J Combined Cycle Combustion Turbine (Annual)

Southern Power Company - Trinidad Generating Facility

EPN	Average Heat Input[1] (MMBtu/hr)	Annual Heat Input[2] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[3]	GHG Mass Emissions[4] (tpy)	Global Warming Potential[5]	CO_2e (tpy)
U1-STK	3,214	28,154,640	CO_2	118.86	1,673,190	1	1,673,190
			CH_4	2.2E-03	31.0	21	651.7
			N_2O	2.2E-04	3.1	310	962.1
				Total:	**1,673,224**		**1,674,804**

Note

1. *The average heat input for the MHI J scenario is based on the HHV heat input at 100% load, with duct burner firing, at 65 ^oF ambient temperature.*
2. *Annual heat input based on 8,760 hours per year operation.*
3. *CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
4. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = CO_2 emitted from combustion, tons/yr

F_c = Carbon based F-factor,1040 scf/MMBtu

H = Heat Input (MMBtu/yr)

U_f = 1/385 scf CO_2/lbmole at 14.7 psia and 68 ^oF

MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lb-mole

5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-3
GHG Emission Calculations - MHI J Combined Cycle Combustion Turbine (Hourly)
Southern Power Company - Trinidad Generating Facility

Max Hourly GHG Emissions From MHI J Turbine

EPN	Max Hourly Heat Input[1] (MMBtu/hr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions[3] (ton/hr)	Global Warming Potential[4]	CO_2e (ton/hr)
U1-STK	3,418.0	CO_2	118.86	203	1	203
		CH_4	2.2E-03	0.0038	21	0.0791
		N_2O	2.2E-04	0.0004	310	0.1168
			Total:	**203**		**203**

Startup/Shutdown Hourly GHG Emissions Related to the MHI J Turbine

EPN	Heat Input During Startup[1] (MMBtu/hr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions[3] (ton/hr)	Global Warming Potential[4]	CO_2e (ton/hr)
U1-STK	1,264.0	CO_2	118.86	75	1	75
		CH_4	2.2E-03	0.0014	21	0.0293
		N_2O	2.2E-04	0.0001	310	0.0432
AUXBLR1	110.0	CO_2	116.89	6	1	6
		CH_4	2.2E-03	0.00012	21	0.0025
		N_2O	2.2E-04	0.000012	310	0.0038
			Total:	**82**		**82**

Note

1. The following hourly heat input data are from the Design Basis document for MHI J unit

	Operating Mode	Site Condition	Turbine Heat Input MMBtu/hr, HHV	Duct Burner Heat Input MMBtu/hr, HHV	Total Hourly Heat Input MMBtu/hr, HHV
Maximum Hourly Heat Input	Base Load, 0 °F Ambient, Duct Burner Firing	Winter, Fired	3,169	249	3,418
Maximum Hourly Heat Input During Startup	-	-	1,264	0	1,264

2. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

3. CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4

$W_{CO2} = (Fc \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = CO_2 emitted from combustion, tons/hr

Fc = Carbon based F-factor,1040 scf/MMBtu

H = Heat Input (MMBtu/hr)

U_f = 1/385 scf CO_2/lbmole at 14.7 psia and 68 ^oF

MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lb-mole

4. Global Warming Potential factors from Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

Table 3-4
GHG Emission Calculations - Auxiliary Boiler
Southern Power Company - Trinidad Generating Facility

EPN	Maximum Heat Input[1] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
AUXBLR1	165,000	CO_2	116.89	9,643	1	9,643
		CH_4	2.2E-03	0.18	21	3.8
		N_2O	2.2E-04	0.018	310	5.6
			Total:	**9,643**		**9,653**

Note
1. *Annual fuel use and heating value of natural gas from Table A-10 State/PSD air permit application*
2. *Factors based on Table C-1 and C-2 of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-5

GHG Emission Calculations - Natural Gas Piping Fugitives

Southern Power Company - Trinidad Generating Facility

EPN	Source Type	Fluid State	Count	Emission Factor[1] (scf/hr/comp)	CO_2[2] (tpy)	Methane[3] (tpy)	**Total (tpy)**
VOC-FUG	Valves	Gas/Vapor	300	0.121	0.096	6.357	
	Flanges	Gas/Vapor	1,200	0.017	0.054	3.573	
	Relief Valves	Gas/Vapor	5	0.193	0.003	0.169	
	Sampling Connections	Gas/Vapor	10	0.031	0.0008	0.0543	
	Compressors	Gas/Vapor	3	0.003	0.000024	0.00158	
GHG Mass-Based Emissions					0.154	10.15	**10.31**
Global Warming Potential[4]					1	21	
CO_2e Emissions					0.154	213.25	**213.40**

<u>Note</u>

1. Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting published in the May 21, 2012 Technical Corrections

2. CO_2 emissions based on vol% of CO_2 in natural gas *0.53%*

3. CH_4 emissions based on vol% of CH_4 in natural gas *96.0%*

4. Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

Example calculation:

300 valves	0.121 scf gas	0.0053 scf CO2	lbmole	44 lb CO_2	8760 hr	ton =	0.096 ton/yr
	hr * valve	scf gas	385 scf	lbmole	yr	2000 lb	

TABLE 3-6

GHG Emission Calculations - Gaseous Fuel Venting During Turbine Shutdown/Maintenance and Small Equipment and Fugitive Component Repair/Replacement

Southern Power Company - Trinidad Generating Facility

Location	Initial Conditions			Final Conditions			Annual Emissions		**Total**
	Volume[1] (ft^3)	Press. (psig)	Temp. (°F)	Press. (psig)	Temp. (°F)	Volume[2] (scf)	CO_2[3] (tpy)	CH_4[4] (tpy)	**(tpy)**
Turbine Fuel Line Shutdown/Maintenance	138	600	50	0	68	6,710	0.0020	0.13	
Small Equipment/Fugitive Component Repair/Replacement	6.7	50	50	0	68	31	0.00001	0.00061	
GHG Mass-Based Emissions							0.0020	0.1344	**0.14**
Global Warming Potential[5]							1	21	
CO_2e Emissions							0.0020	2.8	**2.8**

1. Initial volume is calculated by multpilying the crossectional area by the length of pipe using the following formula: V= pi * [(diameter in inches/12)/2]^2 * length in feet = ft^3

2. Final volume calculated using ideal gas law $[(PV/ZT)_i = (PV/ZT)_f]$. $V_f = V_i\ (P_i/P_f)\ (T_f/T_i)\ (Z_f/Z_i)$, where Z is estimated using the following equation: $Z = 0.9994 - 0.0002P + 3E\text{-}08P^2$.

3. *CO_2 emissions based on vol% of CO_2 in natural gas* 0.53% from natural gas analysis

4. *CH_4 emissions based on vol% of CH_4 in natural gas* 96.0% from natural gas analysis

5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Example calculation:

6710 scf Nat Gas	0.005 scf CO2	lbmole	44 lb CO_2	ton =	=	0.0020	ton/yr CO_2
yr	scf Nat Gas	385 scf	lbmole	2000 lb			

Table 3-7

GHG Emission Calculations - Emergency Firewater Pump Engine

Southern Power Company - Trinidad Generating Facility

Assumptions:

Annual Operating Schedule:	100	hours/year
Power Rating:	160	hp
Max Hourly Fuel Use:	11.2	gal/hr
Heating Value of No. 2 Fuel Oil[1]:	0.138	MMBtu/gal
Max Hourly Heat Input:	1.5	MMBtu/hr
Annual Heat Input:	154.6	MMBtu/yr

EPN	Heat Input (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
FWP1-STK	154.6	CO_2	163.05	12.6	1	12.6
		CH_4	6.6E-03	0.0005	21	0.0
		N_2O	1.3E-03	0.0001	310	0.0
			Total:	**12.60**		**12.64**

Calculation Procedure

Annual Emission Rate = annual heat Input X Emission Factor X 2.2 lbs/kg X Global Warming Potential / 2,000 lbs/ton

Note

1. *Default high heat value based on Table C-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
2. *GHG factors based on Tables C-1 and C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-8

GHG Emission Calculations - Electrical Equipment Insulated With SF_6

Southern Power Company - Trinidad Generating Facility

Assumptions

Insulated circuit breaker SF_6 capacity:	365	lb
Estimated annual SF_6 leak rate:	0.5%	by weight
Estimated annual SF_6 mass emission rate:	0.0009	ton/yr
Global Warming Potential[1]:	23,900	
Estimated annual CO_2e emission rate:	21.8	ton/yr

<u>Note</u>

Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

4.0 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

This project involves the construction of a new unit at a greenfield site. Based on the GHG potential emission calculations provided above, this project will emit GHG emissions (sum of six GHG) in excess of the applicable 100,000 tons per year CO_2e and zero tpy mass basis PSD permitting thresholds established by the Tailoring Rule. The GHG emissions increases associated with this project will therefore trigger PSD permitting under the Tailoring Rule as shown in the table below.

Regulated PSD Pollutants	Permitting Threshold (tpy)	Project Emissions (tpy)	PSD?
One CT/HRSG Unit and Associated Ancillary Equipment			
GHG (CO2e)	>100,000	1,684,707	YES
GHG (mass)	> 100	1,682,891	YES

The potential GHG emissions are documented on the attached TCEQ PSD netting tables: Table 1F and Table 2F. Also included in Appendix A is the “The GHG PSD APPLICABILITY FLOWCHART – NEW SOURCES” from the *PSD and Title V Permitting Guidance for Greenhouse Gases.*

In accordance with this PSD applicability determination, the top-down GHG BACT analyses are provided in this application for all sources of GHGs for the proposed project.

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: TBD				Application Submittal Date: 06/27/2013			
Company Southern Power Company							
RN: TBD				Facility Location:			
City: Trinidad				County: Henderson			
Permit Unit I.D.: U1-STK (MHI J)				Permit Name: Trinidad Generating Facility			
Permit Activity: ☑ New Source				☐ Modification			
Project or Process Description: Construction of a combined cycle power plant (1 x 1 x 1 configuration)							
Complete for all pollutants with a project emission increase.	**POLLUTANTS**						
	Ozone					**Other[1]**	
	NOx	**VOC**	**CO**	**SO_2**	**PM**	**GHG**	**CO_2e**
Nonattainment?						No	No
PSD?						Yes	Yes
Existing site PTE (tpy)			**This form for GHG only**			0	0
Proposed project increases (tpy from 2F)[2]						1,682,891	1,684,707
Is the existing site a major source?						No	No
If not, is the project a major source by itself?						Yes	Yes
If site is major, is project increase significant?							
If netting required, estimated start of construction:							
5 years prior to start of construction:						contemporaneous	
Estimated start of operation:						period	
Net contemporaneous change, including proposed project, from Table 3F (tpy)[3]						1,682,891	1,684,707
Major FNSR applicable?						Yes	Yes

1. Other PSD pollutants
2. Sum of proposed emissions minus baseline emissions, increases only.
3. Since there are no contemporaneous decreases which would potentially affect PSD applicability and an impacts analysis is not required for GHG emissions, contemporaneous emission changes are not included on this table.

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

Susan Comensky	VP, External and Regulatory Affairs	6/27/13
Signature	Title	Date

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	GHG	**Permit:**	TBD
Baseline Period:	N/A **to** N/A		

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (B - A)[6]	Correction[7]	Project Increase[8]
1	CTG1/HRSG1	U1-STK	TBD	0.00	0.00	1,673,224		1,673,224		1,673,224
2	AUXBLR1	AUXBLR1	TBD	0.00	0.00	9,643		9,643		9,643
3	VOC-FUG	VOC-FUG	TBD	0.00	0.00	10		10		10
4	TURB-MSS	TURB-MSS	TBD	0.00	0.00	0.14		0		0
5	FWP1	FWP1-STK	TBD	0.00	0.00	13		13		13
6	SF6-FUG	SF6-FUG	TBD	0.00	0.00	0.0009		0.0009		0.0009
7										
8										
9										
10										
11										
12										
14										
15										
							Page Subtotal[9]			1,682,891

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	CO_2e	**Permit:**	TBD
Baseline Period:	N/A **to** N/A		

Affected or Modified Facilities[2]			Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (B - A)[6]	Correction[7]	Project Increase[8]
	FIN	EPN								
1	CTG1/HRSG1	U1-STK	TBD	0.00	0.00	1,674,804		1,674,804		1,674,804
2	AUXBLR1	AUXBLR1	TBD	0.00	0.00	9,653		9,653		9,653
3	VOC-FUG	VOC-FUG	TBD	0.00	0.00	213		213		213
4	TURB-MSS	TURB-MSS	TBD	0.00	0.00	3		3		3
5	FWP1	FWP1-STK	TBD	0.00	0.00	13		13		13
6	SF6-FUG	SF6-FUG	TBD	0.00	0.00	22		22		22
7										
8										
9										
10										
11										
12										
13										
14										
15										
							Page Subtotal[9]			1,684,707

All emissions must be listed in tons per year (tpy). The same baseline period must apply for all facilities for a given NSR pollutant.

1. Individual Table 2F's should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

EPA's PSD rules define BACT as follows:

> *Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.[13]

In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommends the continued use of the Agency's existing five-step "top-down" BACT process to determine BACT for GHGs.[14] In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. Once technically feasible options are identified and ranked based on control effectiveness, the permit applicant should first examine the highest-ranked ("top") option. The top-ranked option should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative is to be evaluated, and so on, until an option is selected as BACT.

EPA has broken down this analytical process into the following five steps:

- Step 1: Identify all available control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies

[13] 40 C.F.R. § 52.21(b)(12.)
[14] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (Nov. 2010).

- Step 4: Evaluate most effective controls and document results
- Step 5: Select the BACT.

5.1 BACT FOR THE NATURAL GAS-FIRED COMBINED-CYCLE UNIT

5.1.1 Step 1: Identify All Available Control Technologies

The options for controlling GHG emissions, including CO_2, CH_4, and N_2O, can be divided into two categories: Post-Combustion Technologies and Supply-Side Energy Efficiency.

5.1.1.1 Post-Combustion Options

Carbon Capture Sequestration - (CCS)

As EPA states in its GHG BACT Guidance, "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants...[and] should be listed in Step 1 of a top-down BACT analysis for GHGs. This does not necessarily mean CCS should be selected as BACT for such sources."[15]

The CCS process is defined by the Interagency Task Force on CCS as "a three-step process that includes capture and compression of CO_2 from power plants or industrial sources; transport of the captured CO_2 (usually in pipelines); and storage of that CO_2 in geologic formations, such as deep saline formations, oil and gas reservoirs, and un-mineable coal seams."[16]

There are no other potentially available post-combustion control technologies for CO_2, CH_4, or N_2O identified at this time.

5.1.1.2 Efficient Processes, Practices, and Design Options

EPA Region 6 has concluded in recent greenhouse gas permitting decisions that the proposed energy efficient processes, practices, and designs discussed below are available for combined-cycle combustion turbine power generators.

Combustion Turbine Efficient Processes, Practices, and Designs

Combustion Turbine Design

CO_2 is a product of combustion of fuel containing carbon, which is inherent in any power generation technology using fossil fuel. It is not possible to reduce the amount of CO_2 generated from combustion, as CO_2 is the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. As

[15] http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf (pg.32)
[16] http://fossil.energy.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf

such, there is no technology available that can effectively reduce CO_2 generation by adjusting the conditions in which combustion takes place.

Reducing the amount of CO_2 generated by a fuel-burning power plant per unit of power produced can be accomplished by reducing the amount of fuel combusted to meet the plant's required power output. This result is obtained by using efficient combustion technologies.

In addition to the high-efficiency primary components of a combustion turbine, there are a number of other design features employed within the turbine and ongoing operational practices that can be implemented to maintain and improve the overall efficiency of the machine. These additional features include those summarized below.

Periodic Burner Maintenance

Regularly scheduled maintenance programs are recommended by manufacturers of modern combustion turbines. These maintenance programs are important for the reliable operation of the unit, as well as to maintain high efficiency. As the combustion turbine is operated over time, the unit experiences degradation and loss in performance. The combustion turbine maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels, commonly referred to as combustion inspections, hot gas path inspections, and major inspections. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to optimize efficient low-emission operation.

Reduction in Heat Loss

Modern combustion turbines have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. To reduce heat loss from the combustion turbine and protect the personnel and equipment around the machine, insulation blankets are applied to the combustion turbine casing. These blankets reduce the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.

Instrumentation and Controls

Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital-type and is supplied with the combustion turbine. The turbine control system controls all aspects of the turbine's operation, including the fuel feed and burner operations, to achieve efficient low-NO_X combustion. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full-load and part-load conditions.

Heat Recovery Steam Generator Efficient Processes, Practices, and Designs

The HRSG takes waste heat from the combustion turbine exhaust and uses the waste heat to convert boiler feed water to steam.

The modern combustion turbine-based combined-cycle HRSG is generally a horizontal gas flow, natural water side circulation, drum-type heat exchanger designed with steam generation sections, reheat sections, superheater sections, steam attemperation equipment, post-combustion emissions control equipment, and condensate recirculation. The HRSG is designed to maximize the conversion of the combustion turbine exhaust gas waste heat to steam for all plant ambient and load conditions. Maximizing steam generation will increase the steam turbine's power generation, which increases plant efficiency.

Heat Exchanger Design Considerations

HRSGs are heat exchangers designed to capture as much thermal energy as possible from the combustion turbine exhaust gases. This is performed at multiple pressure and temperature absorption levels. The HRSG configuration incorporates economizer section(s), evaporator section(s), and superheater section(s). These heat transfer sections are made up of many thin-walled tubes to provide surface area to maximize the transfer of heat to the working fluid. Most of the tubes also include extended surfaces (e.g., fins). The extended surface optimizes the heat transfer, while minimizing the overall size of the HRSG. Additionally, flow guides are used to distribute the flow evenly through the HRSG to allow for efficient use of the heat transfer surfaces and post-combustion emissions control components. Low-temperature economizer sections employ recirculation systems to minimize cold-end corrosion. In aggregate, these design features increase steam generation and thereby enhance plant efficiency.

Insulation

HRSGs take waste heat from the combustion turbine exhaust gas and uses that waste heat to convert boiler feed water to steam. As such, the temperatures inside the HRSG are nearly equivalent to the exhaust gas temperatures of the turbine. For modern combustion turbines, these temperatures can approach 1,200°F at the exhaust. HRSGs are designed to maximize the conversion of the waste heat to steam. One aspect of the HRSG design in maximizing this waste heat conversion is the use of insulation. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack. Insulation reduces heat loss to the surrounding air, thereby improving the overall efficiency of the HRSG.

Minimizing Fouling of Heat Exchange Surfaces

HRSGs are made up of a number of tubes within the shell of the unit that are used to generate steam from the combustion turbine exhaust gas waste heat. To maintain high heat transfer, the tubes and their extended surfaces need to be as clean as possible. Fouling of the tube surfaces impedes the transfer of heat. Fouling occurs from the constituents within the exhaust gas stream. Filtration of the inlet air to the combustion turbine is performed which helps to reduce fouling. Additionally, cleaning of the tubes is performed during periodic outages. By avoiding fouling through air filtration and by cleaning tubes during outages, the efficiency of the unit is maintained.

Minimizing Vented Steam and Repair of Steam Leaks

As with all steam-generated power facilities, minimization of steam vents and repair of steam leaks is important in maintaining the plant's efficiency. A combined-cycle facility has just a few locations where steam is vented from the system, including at the deaerator vents, blowdown tank vents, and vacuum pumps/steam jet air ejectors. Although these vents are necessary to maintain the overall heat transfer within the HRSG and condenser by removing solids and air that potentially blankets the heat transfer surfaces, thereby lowering the equipment's performance, the steam that is lost through these vents can have a counterbalancing impact on efficiency. Steam leaks are repaired as soon as possible and steam vents will be used only when necessary to maintain overall facility performance.

Steam Turbine Efficient Processes, Practices, and Designs

The steam turbine for this project will be a modern, high-efficiency, reheat, condensing unit. Modern turbines employ both impulse and reaction blading. The overall efficiency of the unit is affected by a number of items, including the inlet steam conditions, the exhaust steam conditions, the blading design, the turbine seals, and the generator efficiency.

Use of Reheat Cycles

The efficiency of a steam turbine is directly related to the steam conditions entering the turbine. The higher the steam temperature and pressure, the higher the overall efficiency. To achieve the higher temperatures, reheat cycles are employed. This is necessary to reduce the moisture content of the exhaust steam. If the moisture content of the exhaust steam is too high, erosion of the last-stage turbine blades occurs, which can affect turbine efficiency. In addition, this cycle reheats partially expanded steam from the steam turbine, increasing the energy in the steam. The steam turbine extracts this additional energy increasing the overall efficiency of the cycle.

Use of Exhaust Steam Condenser

Steam turbine efficiency is also improved by lowering the exhaust steam conditions of the unit. The lower the exhaust pressure, the higher the overall turbine efficiency. For high-efficiency units, the exhaust steam is saturated under vacuum conditions. This is accomplished by the use of a condenser. The condenser is typically a shell and tube heat exchanger with cooling water flowing through the tubes and the turbine exhaust steam condensing in the shell. The condensing steam creates a vacuum in the condenser, which increases steam turbine efficiency. This vacuum is dependent on the temperature of the cooling water. As the temperature of the cooling water is lowered, the absolute vacuum attainable is lowered and the steam turbine is more efficient.

Efficient Blading Design

Blading design also affects the overall efficiency of the turbine. The blade design has evolved for high-efficiency transfer of the energy in the steam to power generation. Additionally, 3-D computer-aided design technology is also employed to provide higher efficiency blade design. Blade materials are also important components in blade design, which allow for high-temperature and large exhaust areas to improve performance.

Turbine seals are also important in the overall performance of the steam turbine. The high-pressure steam will leak to the atmosphere along the turbine shaft, as well as bypass the turbine stages if sealing is not employed. The steam turbine designers have multiple steam seal designs to increase the efficiency from the steam turbine.

Efficient Steam Turbine Generator Design

The steam turbine generator is also a key element in the overall performance of the steam turbine. The modern generator is a high-efficiency unit. The generator for modern steam turbines is typically cooled by one of three methods. These methods are open-air cooling, totally enclosed water to air cooling, or hydrogen cooling. These cooling methods increase the efficiency of the generator, resulting in an overall high-efficiency steam turbine. According to representatives from the steam turbine vendor, there is no energy penalty between the three cooling methods. The selection of the cooling method will be made by the equipment provider.

5.1.2 Step 2: Eliminate Technically Infeasible Control Options

CCS

When evaluating the feasibility of CCS, unlike any other control option, the feasibility of three requisite components must be evaluated: capture; compression and transport; and sequestration. The integration of these three components as well as the legal issues associated with CCS must also be included in its feasibility evaluation.

CO_2 Capture

Capturing CO_2 is a technology that has not been applied at full scale to power plants. CO_2 gas separation technologies have been developed and employed in the industrial sector (e.g., petroleum refining and natural gas purification) for more than seventy years.[17] Also, CO_2 capture on a small scale has been happening for many years in the petroleum and industrial chemical industry. However, capturing CO_2 on the commercial scale of a power plant has never been performed, in the U.S. or abroad. There are various pilot scale and demonstration projects either already underway or soon-to-be in operation that are testing technologies that could one day be used at this scale. Several of these projects are listed in Table 5-1.

[17] http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf

There are several methods to remove CO_2 from flue gas that are being developed and demonstrated at various capacities. The most studied post-combustion CO_2 removal processes to date employ reagents or sorbents that include the following: ammonia, monoethanolamine (MEA) or other amine-based reagents, and various solid sorbents.

Amine-based systems are the subject of intense study for utility application. However, amine-based reagents are in the early stages of development for use in electric generating units.[18] The amount of energy required to regenerate the CO_2 presents a challenge to commercial viability of such processes. In addition, many of these reagents can be impacted by exposure to compounds found in flue gas, such as oxygen, trace concentrations (10-20 ppm) of SO_2, and NO_x.

Several suppliers are developing amine-based systems for utility application by extrapolating designs from small-scale industrial applications. Table 5-1 presents a partial summary of projects either completed or in progress that entail testing of pilot plant and demonstration equipment.

TABLE 5-1 PARTIAL LIST OF COMPLETED/IN-PROGRESS POST-COMBUSTION CO2 PILOT-PLANT AND DEMONSTRATION TESTS

Commercial Supplier	Reagent	Location	Experience
Alstom	Advanced amine technology	Dow Chemical, S. Charleston, W. VA.	2 MW pilot plant started in Sept. 2009, for 2 year term.
Alstom	Ammonia (chilled)	AEP Mountaineer Plant, New Haven, WV	20 MW unit operated from Sept. 2009-May 2011
Siemens	Amino acid	E. On Staudinger Facility, Germany	1 MW pilot plant operating since Sept. 2009
Mitsubishi Heavy Industries	Advanced amine technology	Plant Barry, Mobile, AL	25 MW demonstration of CO_2 capture (2011) and sequestration (2012)

MEA-based processes are being evaluated including the Fluor ECONAMINE FG+ process, which uses a special inhibitor to resist corrosion and degradation from the oxygen. Alstom is exploring an amine-based process with Dow Chemical Company. Also, as shown in Table 5-1, Mitsubishi Heavy Industries and Southern Company are demonstrating a process using proprietary KS-1, developed by Mitsubishi and Kansai Electric Power Company.

[18] These other amine compounds, dry sorbents, and ammonia, as well as special-purpose compounds are presently being developed with DOE/NETL and private industry funding.

Amine-based processes are not the only post-combustion CO_2 capture option. Siemens is developing an amino acid-based process (Jockenhoevel, 2008), and Alstom is demonstrating an ammonia-based process.

Significantly, all of these research projects and demonstration applications are pre-commercial – that is, they are not proven to deliver reliable, continuous CO_2 removal for utility scale applications at this time. EPA has acknowledged that this technology is not ready to be implemented on commercial-scale power plants. In the "PSD and Title V Permitting Guidance for Greenhouse Gases," EPA says they support the following statement which was originally found in the Interagency Task Force on CCS Report[19]:

> "Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."

CO_2 Compression and Transport

After CO_2 is captured, it must be compressed "from near atmospheric pressure to a pressure between 1,500 and 2,200 psia in order to be transported via pipeline and then injected into an underground storage site."[20] Compressing CO_2 is energy intensive and expensive. The Department of Energy (DOE) National Energy Technology Laboratory (NETL) is working to develop concepts for large-scale CO_2 compression that will reduce the auxiliary power requirements and capital cost. NETL is evaluating various compression concepts using computational fluid dynamics and laboratory testing that will lead to developing prototypes and field testing. Their research efforts include "development of intra-stage versus inter-stage cooling; fundamental thermodynamic studies to determine whether compression in a liquid or gaseous state is more cost-effective; and development of a novel method of compression based on supersonic shock wave technology."[21]

Some pipelines exist today that transport supercritical CO_2. Since the 1970s, CO_2 has been transported in pipelines to oil fields for use in enhanced oil recovery (EOR). Before CCS can become widespread on power plants, an extensive CO_2 pipeline network will need to be created. Currently, there are only approximately 4,000 miles of these pipelines in the U.S., however, not all power plants are located on the existing CO_2 pipelines or near the location of geologic sinks for sequestration.[22] There will be a need for more pipeline capacity to transport the large volumes of CO_2 produced from power plants.

[19] http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf
[20] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf
[21] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf
[22] http://www.sseb.org/wp-content/uploads/2010/05/pipeline.pdf

The CO_2 transported for use in EOR operations has historically been from the steady state production of natural geologic deposits and not from CO_2 captured at power plants. Compression and transportation operations could be affected by the unsteady flow of CO_2 sourced by power plants. See more on this issue in the "Integration" discussion below.

CO_2 Sequestration

CO_2 sequestration is the third-step of the CCS process. It is the injection and long-term storage of CO_2 in geologic formations such as deep saline reservoirs, oil and gas reservoirs, and unmineable coal seams. These are geologic structures that have stored crude oil, natural gas, brine, and geologic CO_2 over millions of years; however, sequestration of commercial volumes of CO_2 produced by a power plant has not progressed beyond the research and development phase.

CO_2 Sequestration: Saline Formations

DOE has estimated that the U.S. could potentially store more than 12 trillion tons of CO_2 in deep saline formations.[23] Sustained injection operations and monitoring of CO_2 in saline formations in the U.S. has not progressed beyond the research and development phase. In Algeria and the North Sea, commercial scale CO_2 sequestration is taking place but not with CO_2 captured from a power plant. Table 5-2 lists various saline sequestration projects around the world.

TABLE 5-2 COMMERCIAL SCALE INJECTION PROJECTS

Owner/Operator	Location	Amount Sequestered
In-Salah (a joint venture of Sonartrach, BP, and Statoil)	Algeria in North Africa	1 million ton/year since 2004; Source: natural gas upgrading operations
Statoil (Norwegian oil company)	Utsira Sand, saline formation under the North Sea associated with the Sleipner West Heimedel gas reservoir	Approximately 1 million tons/year; equivalent to the output of a 150 MW coal-fired power plant; Source: natural gas upgrading operations
Southeast Regional Carbon Sequestration Partnership	Cranfield storage site in Mississippi	Approximately 100,000 tons/month (over 6.6 million tons since 2010); Source: Jackson Dome geologic source
Midwest Regional Carbon Sequestration Partnership	Mt. Simon Sandstone formation in Illinois	Approximately 400,000 tons since 2011; Source: ethanol plant

SPC is and has been involved in CO_2 saline sequestration research projects both on its own and as part of the Southeast Regional Carbon Sequestration Partnership (SECARB). Below are descriptions of these projects:

[23] http://www.fossil.energy.gov/programs/sequestration/geologic/

Plant Daniel Pilot Injection Project: This project was conducted by SECARB and involved drilling an injection well and an observation well into the Tuscaloosa Formation in South Mississippi at Plant Daniel. Approximately 3,000 tons of CO_2 were injected into a saline formation approximately 8,500 ft underground. The injection was completed in the fall of 2008 and monitoring was completed in 2010. The project included successful site characterization, permitting, injection operations, and monitoring of the CO_2 in the subsurface.

Plant Barry Anthropogenic CCS Demo/SECARB Phase III: Southern Company has been operating a 25 MW slip stream amine capture plant at Plant Barry since June 2011. Injection operations began in 2012. The project will provide CO_2 for the DOE regional sequestration partnership SECARB phase 3 large volume sequestration demonstration project. The SECARB project includes drilling two injection wells and two observation wells into the Paluxy saline formation located geologically above the Citronelle Oil Field in South Alabama. The project will inject 100,000-150,000 tons of CO_2 per year for up to three years with monitoring for three to four additional years. The project also includes construction and operation of a twelve mile pipeline that will connect Plant Barry to the injection site. The project will confirm effective monitoring and verification protocols for geologic sequestration, address regulatory and permitting issues, and cultivate public education and outreach internally and externally. It is also one of the first projects in the world to study the integration of CO_2 capture operations at a coal plant with pipeline transportation and saline reservoir injection.

CO_2 Sequestration: Oil and Gas Reservoirs: For years, CO_2 has been used in EOR and enhanced gas recovery. In this process, CO_2 is pumped into an oil or gas reservoir to push out the product. During this process, some CO_2 is trapped in the reservoir. The U.S. is the world leader in EOR technology and uses over 32 million tons of CO_2 for this purpose.[24] The CO_2 used in EOR operations has historically been from the steady state production of natural geologic deposits and not from CO_2 captured at power plants. EOR operations can be affected by the variability and purity of the CO_2 sourced by power plants.

EOR is not available in all areas of the U.S. so it cannot be the answer for CO_2 sequestration for all power plants.

CO_2 Sequestration: Coal Seams: Coal seams (a.k.a., coal beds) contain large amounts of methane-rich gas that can be recovered by depressurizing the seam which can be done by injecting CO_2 into the formation. According to DOE, tests have shown the adsorption rate for CO_2 to be twice that of methane, “giving it the potential to efficiently displace methane and remain stored in the bed.” However DOE also acknowledges that the “CO_2 recovery of coal-bed methane has been demonstrated in limited field tests, but much more work is necessary to understand and optimize the process.”[25]

[24] http://www.fossil.energy.gov/programs/sequestration/geologic/
[25] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf

SPC participated in a SECARB project that evaluated the feasibility of combining carbon sequestration and enhanced recovery of coal bed methane. This project, the Black Warrior Basin Coal Seam Pilot Injection Project, injected 240 tons of CO_2 into coal seams at depths ranging from 940 feet to 1,800 feet. This project began in 2009 with the injection operations finalized in 2010. Monitoring will continue for several years to evaluate the methane recovery potential from the injection.

Integration

CO_2 capture, transport, and sequestration have never before been integrated at commercial scale on a power plant. The integration of these processes on a power plant could result in operational issues and other unknowns. Problems could result from load fluctuations, outages, and CO_2 purity. Also, the reliability of the host generating unit could be affected by problems associated with the CCS processes.

Integration: Loading: Power plants do not run consistently; their load fluctuates as needed to meet electricity demand which may affect the CCS equipment. EOR operations historically have been supplied with CO_2 from some steady source such as a natural geologic deposit of CO_2 or from a natural gas purification process. The knowledge available on CO_2 sequestration is mostly from EOR operations. Therefore, it is unknown how the processes of CO_2 sequestration could be impacted by inconsistent CO_2 flow.

Integration: Outages: Power plants experience planned and forced outages. During these outages, the CCS processes would be suspended. It is unknown how this suspension will affect the injection operations and equipment.

Integration: CO_2 Purity: The CO_2 from power plants may not be the same as the CO_2 that is produced from natural geologic deposits or from natural gas purification processes. It is unknown how streams of varying purity CO_2 will be able to be integrated into the same pipeline network.

Integration: Reliability: Reliability of a CCS system including the host power plant could be affected by problems arising in each CCS process. Because CO_2 capture, transport, and sequestration have not been integrated on a power plant before, it is unknown how the three processes will interact with each other. For example, it is unknown how problems at the capture unit will affect the injection sequestration operations. If the capture unit goes down and the CO_2 injection process stops, there could be implications to the geologic sequestration formation. If the CO_2 cannot be injected, the host power plant may not be able to run unless it is able to emit its CO_2 emissions while the problems in the CCS processes are addressed. Problems in one CCS process will likely affect the operations of another process and thus impact the reliability of the system and potentially the ability of the host power plant to operate.

Southern Company is involved in several demonstration projects that will provide some experience with the integration of CCS' three-step process (i.e., capture, compression and transport, sequestration) on a commercial scale power plant. As these projects show, CCS is currently far from a demonstrated CO_2 control technology at commercial scale on a power generation unit and requires much additional study. As mentioned above, Southern Company's Plant Barry Anthropogenic CCS Demo/SECARB Phase III project, which began integrated operation in 2012, is one of the first projects in the world to study the integration of CO_2 capture operations at a coal plant with pipeline transportation and saline reservoir injection. However, this project is not commercial scale and the operation of the generating units is not dependent on the operation of the capture system. Also, SPC plans to gain experience with the integration of CO_2 capture operations with pipeline transport and EOR with Mississippi Power's Kemper County Energy Facility beginning in 2014. The Kemper Project is a DOE Clean Coal Power Initiative demonstration project. It is an air-blown Integrated Gasification Combined Cycle (IGCC) demonstration project that will allow for pre-combustion capture of 65 percent of the CO_2 emissions. The applicability of the experience gained at the Kemper project once it begins operations is likely limited for many projects, because IGCC with integrated pre-combustion CCS is significantly different than natural gas or pulverized coal with post-combustion add-on CCS technology. Also, the applicability of the Kemper project demonstration to other projects in the future will depend heavily on location, as the captured CO_2 from this project will be sold for EOR. Years of operation of the Kemper project will be required to gain experience for future projects.

CCS Legal Issues

There are legal issues associated with CCS that need to be addressed before CCS can become widespread. These issues include pore-space ownership, long-term liability, and CO_2 pipeline related issues. Some States have enacted laws governing these issues, but they vary. This is a problem for projects that operate in states without such laws and for projects that cover multiple states.

Also, CCS is different from other control technologies because, if required for compliance, responsibility may need to be shared between multiple parties, not just the power plant owner/operator. For example, if EOR is used to sequester CO_2, the power generator will likely have to enter into a contract with a third party to transport the CO_2 and demonstrate sequestration. Under such arrangements where the power plant is dependent on a third party for compliance, there are always risks of contract breeches, dissolution of the contract parties, or other issues that cannot be foreseen that could put the ability of the power plant to meet electricity demand at risk.

CCS Conclusion

As discussed above, CCS has potential to reduce CO_2 emissions through post combustion control technology but, currently, is not a technically feasible technology to be applied to power plants for controlling CO_2 emissions and is therefore dismissed from further consideration in this BACT analysis. Progress needs to be made on each step of the CCS process to ensure that it will work on a commercial scale with the characteristics of a power plant, and the integration of the CCS processes on a commercial scale power plant has yet to be accomplished. As EPA states in its GHG BACT Guidance, "CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type…Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations”.[26]

Though SPC believes the technical infeasibility of CCS for control of CO_2 from power plant operations has been thoroughly explained above, we recognize that other recent GHG applications have included an economic analysis of CCS. The average cost of removal per ton of CO_2 calculated for CCS by other applicants proposing similar technologies using the Department of Energy/National Energy Technology Laboratory cost estimation procedure has been in the range of \$83.53/ton to \$92.65/ton removed and has been deemed economically infeasible in all cases.

5.1.3 Step 3: Rank Remaining Control Options

As discussed above, there are no technically feasible post combustion options for GHG removal on a combined-cycle system at this time. A well-designed efficient unit is the only remaining control option for GHG emissions.

5.1.4 Step 4: Evaluate Remaining Options

A well-designed efficient unit is the only remaining control option for the combined-cycle block. Since all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1.2 of this application are being incorporated into this project, an examination of the energy, environmental, and economic impacts of the efficiency designs and practices is not necessary for this application.

5.1.5 Step 5: Selection of BACT

SPC’s combined-cycle design incorporates elements which will result in reliable and efficient long term operation for the expected operational profile of the unit. Significant design criteria include the gas turbine efficiency and its impact on the overall combined-cycle plant efficiency. The selection of the specific gas turbine to be incorporated in a project is based upon unit efficiency, capacity needs, expected operating profile, and project economics. The utilization of high efficiency gas turbines along with an overall efficient and economic plant design is considered BACT for natural gas-fired combined-cycle applications.

SPC proposes the following energy efficient design for the proposed combined-cycle combustion unit as BACT for this project:

[26] http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf (pgs. 35-36)

- Efficient Combustion Turbine Processes, Practices, and Designs
    - Efficient turbine design
    - Periodic turbine burner maintenance
    - Reduction in heat loss
    - Instrumentation and controls
- Efficient HRSG Processes, Practices, and Designs
    - Efficient heat exchanger design
    - Insulation of HRSG
    - Minimizing fouling of heat exchange surfaces
    - Minimizing vented steam and repair of steam leaks
- Efficient Steam Turbine Processes, Practices, and Designs
    - Use of Reheat Cycles
    - Use of Exhaust Steam Condenser
    - Efficient Blading Design
    - Efficient Generator Design

To complete the BACT process, an enforceable emission limit must be established if feasible. Such a limit should be able to be "met on a continual basis at all levels of operation," "demonstrate protection of applicable short term ambient standards," and "be enforceable as a practical matter."[27]

To set an enforceable emission limit, the unique characteristics of GHG emissions must be considered. In its final Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act, EPA states that the "common physical properties relevant to the climate change problem shared by the six greenhouse gases include the fact that they are long-lived in the atmosphere."[28] In EPA's definition of "long-lived" it emphasizes that GHGs are well mixed in the atmosphere and therefore emissions from one source are not necessarily going to impact the local environment: "the gas has a lifetime in the atmosphere sufficient to become globally well mixed throughout the entire atmosphere…"[29] Furthermore, there are no established short term (or long term) ambient standards for GHGs.

SPC proposes the limit be set in tons-per-year of CO_2e. This approach is consistent with the nature of GHGs (long-lived gases that only present a potential environmental concern via their contribution to total, long-term atmospheric concentrations). A tons-per-year limit is also consistent with EPA's use of this measure in its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule and its Mandatory GHG Reporting Program. As mentioned above, EPA requires reporting of annual tons of CO_2e emissions and so an annual CO_2e ton limit would be straightforwardly enforceable as a practical matter. Therefore, a GHG BACT limit for the natural gas-fired combined-cycle of 1,674,804 short tons of CO_2e per 12-month block is proposed (calculated each month as the summation of the emissions from the previous twelve months). A Part 75 compliant monitoring system will be utilized to determine

[27] *New Source Review Workshop Manual*, DRAFT, October 1990, B.V.
[28] 74 Fed. Reg. 66517
[29] Id.

the actual CO_2 portion of the GHG emissions. Heat input and emission factors from the GHG Mandatory Reporting Rule will be used to determine the CH_4 and N_2O portions (including Global Warming Potentials of 21 for CH_4 and 310 for N_2O). This annual limit will take into account all GHG emissions from the combined-cycle unit. The tpy emission calculations are included at the end of Section 3.0 of this application in Table 3-2.

In order to account for the continued operation of the unit in an energy efficient manner, SPC proposes a limit of 922 lb CO_2/MW-hr (gross) (12-month block average, calculated each month by dividing the previous 12 month total CO_2 emissions by the previous 12 month total gross generation, excluding periods of startup and shutdown as defined in Section 2.2) for the combined-cycle block. The CO_2 and MW-hr (gross) would be monitored consistent with the requirements of 40 CFR 60, Part 75. This proposed limit was established to account for low load operations, duct firing, design margin, and equipment degradation. Note that these rates reflect the facility's "gross" power production, meaning the denominator is the total amount of power produced by the plant, and does not exclude auxiliary load consumed by operation of the plant. The emission calculations for the proposed lb CO_2/MW-hr (gross) limit are included in Table 5-4 and are described below.

The proposed lb CO_2/MW-hr (gross) efficiency limit is based on design heat rate data provided by the equipment manufacturer and estimated CO_2 emissions calculated using 40 CFR Part 75, Appendix G, Equation G-4. To establish an enforceable condition that can be met on a continuous basis, SPC started with the turbine's design gross heat rate representative of the 50% load case at 65ºF ambient conditions and then calculated a compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. The following compliance margins are added to the base heat rate:

- A 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design efficiency.
- A 6% performance margin reflecting efficiency losses due to gas turbine degradation prior to maintenance overhauls.
- A 3% degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

Design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, SPC includes a design margin of 3.3% to address such items as equipment underperformance and short-term degradation.

To establish an enforceable BACT condition that can be achieved over the life of the facility, the permit limit must also account for anticipated degradation of the equipment over time between regular maintenance cycles. The manufacturer's degradation curves project an anticipated degradation rate of 5% within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, the projected 5%

degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbines. Therefore, SPC proposes that, for purposes of deriving an enforceable lb CO_2/MW-hr (gross) BACT limitation, gas turbine degradation may reasonably be estimated at 6%.

Finally, in addition to the degradation from normal wear and tear on the combustion turbine, SPC is also providing a reasonable compliance margin based on potential degradation in other elements of the combined cycle plant that would cause the overall plant efficiency to fall. Degradation in the performance of the heat recovery steam generator, steam turbine, heat transfer, cooling tower, and ancillary equipment such as pumps and motors is also expected to occur over the course of a major maintenance cycle.

SPC is proposing the following BACT limits for the Natural Gas Combined-Cycle Unit:

TABLE 5-3 BACT SUMMARY

Unit	Tons of CO_2e per year	Output Based Emission Limit (lb CO_2/MWh gross)
MHI J Combined-Cycle	1,674,804	922

The calculation of the lb CO_2/MWh value is provided on Table 5-4.

On April 13, 2012, EPA's proposed New Source Performance Standard (NSPS), Subpart TTTT, which would establish limits for GHG emissions from new power plants, was published in the Federal Register. The proposed rule would apply to new fossil-fuel fired steam electric generating units that generate electricity for sale and are larger than 25 MW. The EPA proposed an output based standard of 1,000 lb CO_2/MWh gross, with compliance based on a 12-month rolling average. Once finalized, NSPS are applicable to covered sources retroactive to the date of their proposal. Based on the date of the proposal, under language included in the Clean Air Act, EPA should have final action on this proposal by April 13, 2013. At the time of submittal, no action has been taken by EPA.

SPC performed a search of the EPA's RACT/BACT/LAER Clearinghouse for natural gas fired combustion turbine generators and found a limited number of entries which address BACT for GHG emissions. Although not all listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was performed by the following eight natural gas-fired power generation facilities: Russell City Energy Center, Palmdale Hybrid Power Plant, Lower Colorado River Authority Ferguson Plant, Pioneer Valley Energy Center, Cricket Valley Energy Center, Calpine Deer Park Energy Center, Calpine Channel Energy Center, and La Paloma Energy Center.

Table 5-5 below presents a summary of the type(s) of units at these facilities and their proposed or permitted BACT limits.

Table 5-4
GHG Emission Calculations - Calculation of Design Heat Rate and Output Limits for Combined-Cycle - MHI J
Southern Power Company - Trinidad Generating Facility

<u>**50% Load, 65F Ambient Temperature, Without Duct Burner Firing**</u>

	Gross Basis	
Base Heat Rate:	**6,876**	Btu/kWh (HHV)
Design Margin:	3.3%	
Performance Margin:	6.0%	
Degradation Margin:	3.0%	
Adjusted Base Heat Rate with Compliance Margins:	**7,754**	Btu/kWh (HHV)

EPN	Base Heat Rate (Btu/kWhr)	Electrical Output Basis	Heat Input Required to Produce 1 MW (MMBtu/MWhr)	Pollutant	Emission Factor (lb/MMBtu)	lb GHG/MWhr[1]
U1-STK	7,754	Gross	7.75	CO_2	118.86	921.67

<u>Note</u>
1. CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4
$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$
W_{CO2} = CO_2 emitted from combustion, tons/yr
F_c = Carbon based F-factor,1040 scf/MMBtu
H = Heat Input (MMBtu/yr)
U_f = 1/385 scf CO_2/lbmole at 14.7 psia and 68 ^oF
MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lbmole

Table 5-5
Natural Gas Fired Combustion Turbine GHG BACT Comparison Table
Southern Power Company - Trinidad Generating Facility

Facility Name	Permit Date	Permit Number	Plant Size	Location	Plant Type	Type(s) of Units	Output-Based GHG Emission Limit	Heat Rate Limit	Averaging Period
Russell City Energy Center	02/03/10	15487	612 MW	Hayward, CA	Natural gas fired combined cycle plant	Siemens/Westinghouse 501F with 200 MMBtu/hr duct burners (2 on 1 configuration)		7730 Btu (HHV)/kWh (net) without duct firing (ISO Conditions)	Annual heat rate performance test at maximum load
Pioneer Valley Energy Center	04/12/13	052-042-MA15	431 MW	Westfield, MA	New Natural Gas Fired Combined Cycle	One Mitsubishi M501G Turbine without duct firing (1 on 1 Configuration)	825 lb CO_2e/MWh_{grid}, (initial limit) and 895 lb CO_2e/MWh_{grid} (rolling average)		365-day rolling average
Cricket Valley Energy Center	09/12/13	3-1326-00275/00004	1,000 MW	Dover, NY	New Natural gas fired combined cycle	Three GE 7FA turbines with 596.8 MMBtu/hr duct burners) (3 on 3 configuration)	None	The permit states the facility is subject to a CO2 Budget Trading Program but there is no heat rate limit in permit. Applicant proposed 7605 Btu/kWh (HHV) (ISO conditions and no Duct Burner-firing) in application. The application does not specify whether it is on a gross electrical output basis or net electrical output basis.	
Palmdale Hybrid Power Project	10/11/13	SE-09-01	570 MW	Palmdale, CA	New Natural gas fired combined cycle	Two GE 7FA turbines with 500 MMBtu/hr duct burners. (2 combustion turbine on 1 steam turbine configuration)	774 lb CO_2/MWh (net)	7319 Btu (HHV)/kWh (net)	365-day rolling average
LCRA Ferguson Plan	11/11/13	PSD-TX-1244-GHG	590 MW	Marble Falls, TX	New Natural gas fired combined cycle	Two GE 7FA turbines (without duct burners) (2 on 1 configuration)	0.459 ton (918 lbs)CO_2/MWh (net)	7720 Btu (HHV)/kWh (net)	365-day rolling average
Deer Park Energy Center	11/12/13	PSD-TX-979-GHG	180 MW	Deer Park, TX	Natural Gas/Refinery Gas Fired Cogeneration unit added to existing power plant.	One Siemens FD-2 501F with 725 MMBtu/hr Duct Burners in Phase 1, upgraded to Siemens FD-3 501F in Phase 2 (5 on 1 configuration + provide steam to neighboring plant)	0.460 ton (920 lb) CO2/MWh (net)	7730 Btu(HHV)/kWh net (ISO conditions, without duct firing)	30-day rolling average
Channel Energy Center	11/12/13	PSD-TX-955-GHG	180 MW	Pasadena, TX	Natural Gas/Refinery Gas Fired Cogeneration unit added to existing power plant.	One Siemens FD-2 501F with 475 MMBtu/hr duct burners in Phase 1, upgraded to Siemens FD-3 501F in Phase 2 (3 on 1 configuration + provided steam to neighboring plant)	0.460 ton (920 lb) CO2/MWh (net)	7730 Btu(HHV)/kWh net (ISO conditions, without duct firing)	30-day rolling average
La Paloma Energy Center	Pending	PSD-TX-1288-GHG	637 - 735 MW	Harlingen, TX	Natural gas fired combined cycle plant	Two Gas Turbines with 750 MMBtu/hr duct burners (3 possible turbine models: GE 7FA, Siemens SGT6-5000F(4) or SGT6-5000F(5)). (2 on 1 configuration)	Output-Based Limits in Draft Permit (excludes startup hours): 934.5 lb CO_2/MWh (gross) with Duct Firing [GE 7FA]; 909.2 lb CO_2/MWh (gross) with Duct Firing [SGT6-5000F(4); 912.7 lb CO_2/MWh (gross) with Duct Firing [SGT6-5000F(5);	Heat Rates in Draft Permit (excludes startup hours): 7,861.8 Btu (HHV)/kWh (gross) with duct firing [GE 7FA] 7,649.0 Btu (HHV)/kWh (gross) with duct firing [SGT6-5000F(4) 7,679.0 Btu (HHV)/kWh (gross) with duct firing [SGT6-5000F(5)	12 operating month average

Although there are differences in the technologies proposed by each plant, as well as differences in the basis of the proposed limits (i.e. net vs. gross output basis, with or without duct burners, mass emission rate limits or not, etc.), the summary presented above demonstrates that the limits proposed by SPC for the TGF are comparable to recently issued permits.

Although several are under construction, none of the power plants that have received GHG permits have yet begun operation. Therefore, long term compliance with their permit limits has not been demonstrated. The GHG BACT limits should meet the twin goals of allowing flexible operation of the combined-cycle unit as well as limiting mass emissions of GHGs to the atmosphere. Output-based limits have the desired effect of promoting operators to seek thermal efficiencies in their unit operations, resulting in increased electrical output for reduced GHG emissions and ton per year limits restrict the total mass emissions of GHG's into the atmosphere.

Therefore, SPC concludes that the combination of the ton per year and output-based limits presented in Table 5-3 are BACT for this project.

6.1 BACT FOR AUXILIARY BOILER

Based on the required steam flow for this project, a natural gas-fired watertube boiler will be installed. The auxiliary boiler will have a nominal rating of 110 MMBtu/hr and will be utilized to facilitate startup of the combined cycle unit. The auxiliary boiler will be limited to 1,500 hours of operation per year.

6.1.1 Step 1: Identify All Control Options

As with the combined-cycle block, the options for controlling GHG emissions can be divided into two categories: Post-Combustion and efficient combustion processes, practices, and designs.

Post-Combustion Options:

CCS was discussed in detail for the Combined-Cycle BACT analysis.

Efficient Combustion Options:

To maximize the efficiency of the project, the auxiliary boiler was sized appropriately to provide all of the steam required by the gas turbine and steam turbine for startup. The boiler design includes an ultra-low NO_x burner and economizer, and a fuel skid. By sizing the auxiliary boiler components to be appropriate for their purposes, emissions are minimized.

Furthermore, the auxiliary boiler will utilize natural gas fuel, which is the lowest carbon fuel available at TGF. Therefore, formation of CO_2 from combustion of the fuel will be minimized.

Good operating and maintenance practices for the boiler will be implemented and will include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintaining the proper air/fuel ratio so that sufficient oxygen is provided to provide complete combustion of the fuel while at the same time preventing introduction of more air than is necessary into the boiler.

The auxiliary boiler is designed for a thermal energy efficiency of approximately 80%. The energy efficient design of the boiler includes insulation to retain heat within the boiler and a computerized process control system that will optimize the fuel/air mixture and limit excess air in the boiler.

6.1.2 Step 2: Eliminate Infeasible Control Options

Carbon Capture and Storage - (CO_2)

CCS was discussed above for the combined-cycle unit, and it was determined that it is technically infeasible for application on a commercial scale power plant at this time. The same holds true for the auxiliary boiler.

6.1.3 Step 3: Rank Remaining Control Options

As discussed above, the only potential post-combustion options for GHG removal are all technically infeasible for application on the auxiliary boiler at this time. This leaves efficient combustion, processes, practices, and designs as the only available control option.

6.1.4 Step 4: Evaluate Remaining Options

Efficient processes, practices, and design considerations are the only remaining control options for the auxiliary boiler.

6.1.5 Step 5: Selection of BACT

Based on this top-down analysis, SPC concludes that the use of natural gas as a low carbon fuel; good operating and maintenance practices; efficient design; and low annual capacity is BACT for the auxiliary boiler. With the limited annual operation of the auxiliary boiler, the total CO_2e emissions from the boiler are no more than 0.6% of the total site-wide emissions.

Among other recently issued or currently pending GHG permits, the Wolverine Power Supply Cooperative permit and the Palmdale Hybrid Power Project permit included BACT determinations for limited use, auxiliary boilers and heaters. The Wolverine Permit included a 72.4 MMBtu/hr diesel-fired auxiliary boiler, limited to 4,000 hours operation per year. The Permit listed BACT for GHG for the auxiliary boiler to incorporate energy efficient equipment wherever practical in the design of the auxiliary boiler. The Wolverine Permit did not include an output based BACT limit for the auxiliary boiler.

The application for the Palmdale Hybrid Power Project (PHPP) was submitted in May 2011 and a draft permit was issued by the Antelope Valley Air Quality Management District in August 2011. The PHPP application proposed the construction of a power plant utilizing natural-gas-fired combustion turbine combined-cycle generators located in Palmdale, California. The project also included a 110-MMBtu/hr natural-gas-fired auxiliary boiler, limited to 500 hours per year operation, and a 40-MMBtu/hr natural-gas-fired heater, limited to 1,000 hours per year operation. The Palmdale Permit listed BACT for GHG for the auxiliary boiler and heater as annual tune-ups. The Palmdale Permit did not include an output based BACT limit for the auxiliary boiler or heater.

6.2 BACT FOR THE EMERGENCY DIESEL-FIRED EQUIPMENT

The only diesel-fueled equipment associated with the proposed project is a 160-bhp firewater pump engine. The firewater pump engine is classified as a standby (emergency) unit to support the generating plant facility's firewater circulation system. During normal plant operation the diesel engine is not running other than for testing. For this reason, run time capacity, reliability, load starting capability and other considerations are also taken into account in addition to the efficiency of the unit. In order to operate the firewater pump engine with minimum emissions using available technology, the Tier classification is applied, per 40 CFR 60.4205. Regulation currently requires a Tier II classification but is phasing in Tier IV classification between 2008 and 2015. Although the Tier IV classification is currently the lowest emission producing option, it is not available at the firewater pump engine rating required for this project.

6.2.1 Step 1: Identify All Control Options

As with the combined-cycle block, the options for controlling GHG emissions can be divided into two categories: Post-Combustion and efficient combustion processes, practices, and designs.

Post-Combustion Options:

CCS was discussed in detail for the Combined Cycle BACT analysis.

Efficient Combustion Options:

For the purposes of maximizing the energy efficiency of this project, the firewater pump system was specifically sized to provide sufficient firewater flow in the event of an emergency. By sizing the engine to be appropriate for its purpose, emissions are minimized.

6.2.2 Step 2: Eliminate Infeasible Control Options

Carbon Capture and Storage - (CO_2)

CCS was discussed above for the combined-cycle unit, and it was determined that it was infeasible for application on a commercial scale power plant at this time. The same would hold true for the emergency firewater pump engine.

6.2.3 Step 3: Rank Remaining Control Options

As discussed above, the only potential post combustion options for GHG removal are all technically infeasible for application on an emergency firewater pump engine at this time. This leaves efficient combustion processes, practices, and design as the only available control option.

6.2.4 Step 4: Evaluate Remaining Options

Efficient combustion considerations are the only remaining control option for the emergency firewater pump engine.

6.2.5 Step 5: Selection of BACT

Based on this top-down analysis, SPC concludes that good operating and maintenance practices; efficient design; and low annual capacity are selected as BACT for the emergency firewater pump engine. With the limited annual operation of the emergency engine, the total CO_2e emissions from the engine are less than 0.001% of the total site-wide emissions.

6.3 BACT FOR NATURAL GAS FUGITIVES

The proposed project will include natural gas piping components. These components are potential sources of methane and CO_2 emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points.

6.3.1 Step 1: Identify All Available Control Technologies

The following technologies were identified as potential control options for piping fugitives:

- Implementation of leak detection and repair (LDAR) program using a hand held analyzer.
- Implementation of alternative monitoring using a remote sensing technology such as infrared cameras.
- Implementation of audio/visual/olfactory (AVO) leak detection program.

6.3.2 Step 2: Eliminate Technically Infeasible Options

The use of instrument LDAR and remote sensing technologies are technically feasible. Since pipeline-quality natural gas is odorized with a small amount of mercaptan, an AVO leak detection program for natural gas piping components is technically feasible.

6.3.3 Step 3: Rank Remaining Control Technologies

The use of a LDAR program with a portable gas analyzer meeting the requirements of 40 CFR 60, Appendix A, Method 21, can be effective for identifying leaking methane. Quarterly instrument monitoring with a leak definition of 10,000 part per million by volume (ppmv) (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75% for valves, relief valves, sampling connections, and compressors and 30% for flanges.[30] Quarterly instrument monitoring with a leak definition of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned a control efficiency of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges.[31] The U.S. EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer for monitoring equipment for leaks in 40 CFR 60.18(g). For components containing inorganic or odorous compounds, periodic AVO walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.[32]

6.3.4 Step 4: Evaluate Remaining Options

The frequency of inspection and the low odor threshold of mercaptans in natural gas make AVO inspections an effective means of detecting leaking components in natural gas service. As discussed in Section 5.5.3, the predicted emission control efficiency is comparable to the LDAR programs using Method 21 portable analyzers.

6.3.5 Step 5: Selection of BACT

Due to the very low volatile organic compound (VOC) content of natural gas, the TGF will not be subject to any VOC leak detection programs by way of its State/PSD air permit, TCEQ Chapter 115 – Control of Air Pollution from Volatile Organic Compounds, New Source Performance Standards (40 CFR Part 60), National Emission Standard for Hazardous Air Pollutants (40 CFR Part 61); or National Emission Standard for Hazardous Air Pollutants for Source Categories (40 CFR Part 63). Therefore, any leak detection program implemented will be solely due to potential greenhouse emissions. Since the uncontrolled CO_2e emissions from the natural gas piping represent approximately 0.01% of the total site-wide CO_2e emissions, any emission control techniques applied to the piping fugitives will provide minimal CO_2e emission reductions.

---

[30] *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, TCEQ, Oct. 2000*
[31] *Id.* at page 52
[32] *Id.* at page 52

6.4 BACT FOR SF_6 INSULATED ELECTRICAL EQUIPMENT

6.4.1 Step 1: Identify All Available Control Technologies

One technology is the use of industry standard SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

One alternative considered in this analysis is to substitute another, non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NIST) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.*[33]

6.4.2 Step 2: Eliminate Technically Infeasible Options

According to the report NIST Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications.[34] It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6-insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture… it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore there are currently no technically feasible options besides use of SF_6.

6.4.3 Step 3: Rank Remaining Control Technologies

The use of industry standard SF_6 technology with leak detection to limit fugitive emissions is the highest ranked control technology that is technically feasible for this application.

6.4.4 Step 4: Evaluate Remaining Options

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers is not technically feasible.

---

[33] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6,* NIST Technical Note 1425, Nov.1997.
[34] *Id.* at 28 – 29.

6.4.5 Step 5: Selection of BACT

Based on this top-down analysis, SPC concludes that using industry standard enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[35] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

[35] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.

7.0 OTHER PSD REQUIREMENTS

7.1 AIR QUALITY IMPACTS ANALYSIS

An air quality impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 or GHGs.*[36]

An air quality impacts analysis for non-GHG emissions is being submitted with the State/PSD/Non-attainment application submitted to the TCEQ.

7.2 GHG PRECONSTRUCTION MONITORING

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

> *EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.*[37]

A pre-construction monitoring analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

7.3 ADDITIONAL IMPACTS ANALYSIS

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions*

[36] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* at 47-49.
[37] *Id.* at 48.

> *contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.*[38]

A PSD additional impacts analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

[38] *Id.* at 48.

8.0 PROPOSED GHG MONITORING PROVISIONS

SPC proposes to monitor CO_2 emissions by monitoring the quantity of fuel combusted in the turbine and HRSG and performing periodic fuel sampling as specified in 40 CFR 75.10(3)(ii) (refer to procedure below). Results of the fuel sampling will be used to calculate a site-specific Fc factor, and that factor will be used in the equation below to calculate CO_2 mass emissions.

The SPC natural gas-fired turbine will comply with the fuel flow metering and Gross Calorific Value (GCV) sampling requirements of 40 CFR Part 75, Appendix D. The site-specific Fc factor will be determined using the ultimate analysis and Gross Calorific Value in equation F-7b of 40 CFR 75, Appendix F. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR 75, Appendix F, §3.3.6.

The procedure for estimating CO_2 Emissions specified in 40 CFR 75.10(3)(ii) is as follows:

Affected gas-fired and oil-fired units may use the following equation:

$$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2{,}000$$

Where:

W_{CO2} = *CO_2 emitted from combustion, tons/hr*

MW_{CO2} = *molecular weight of CO_2, 44.0 lb/lbmole*

F_c = *Carbon based F-factor, (1,040 scf/MMBtu for natural gas <u>or a site-specific F_c factor</u>)*

H = Hourly heat input in MMBtu, as calculated using the procedure in 40 CFR 75, Appendix F, §5)

U_f = *1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F*

The requirements for fuel flow monitoring and quality assurance in 40 CFR 75 Appendix D are as follows:

Fuel flow meter: meet an accuracy of 2.0 %, required to be tested once each calendar quarter (40 CFR 75, Appendix D, §2.1.5 and §2.1.6(a))

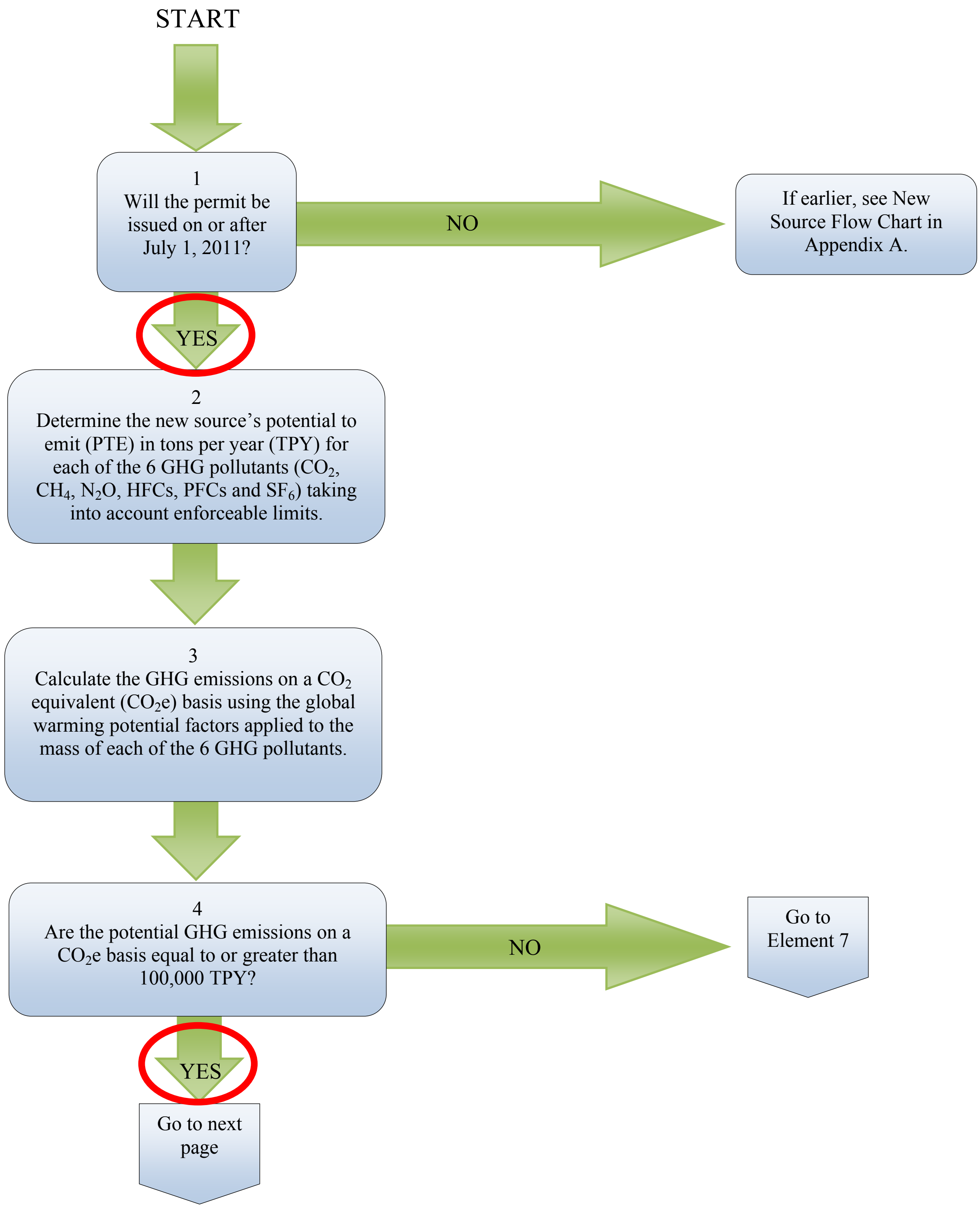
Gross Calorific Value (GCV): determine the GCV of pipeline natural gas at least once per calendar month (40 CFR 75, Appendix D, §2.3.4.1)

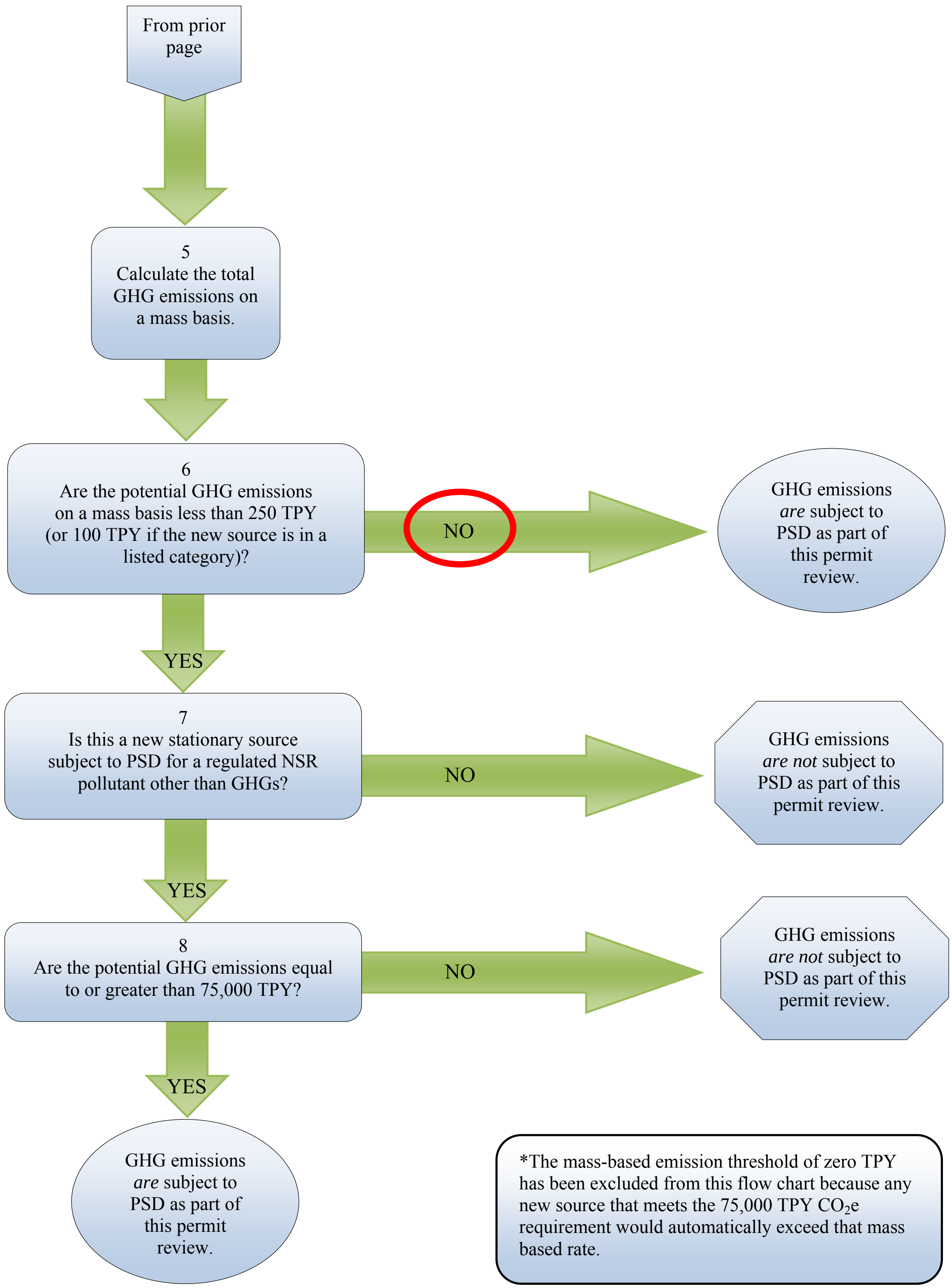
This monitoring approach is consistent with the CO_2 reporting requirements of the GHG Mandatory Reporting Rule for Electricity Generation (40 CFR 98, Subpart D). Subpart D requires electric generating sources that report CO_2 emissions under 40 CFR 75 to report CO_2 under 40 CFR 98 by converting CO_2 tons reported under Part 75 to metric tons.

APPENDIX A

GHG PSD APPLICABILITY FLOWCHART – NEW SOURCES

Appendix A - GHG Applicability Flow Chart – New Sources (On or after July 1, 2011)




From prior page
5
Calculate the total GHG emissions on a mass basis.
6
Are the potential GHG emissions on a mass basis less than 250 TPY (or 100 TPY if the new source is in a listed category)?
NO
GHG emissions *are* subject to PSD as part of this permit review.
YES
7
Is this a new stationary source subject to PSD for a regulated NSR pollutant other than GHGs?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
8
Are the potential GHG emissions equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.
*The mass-based emission threshold of zero TPY has been excluded from this flow chart because any new source that meets the 75,000 TPY CO_2e requirement would automatically exceed that mass based rate.